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BEFORE THE ARIZONA CORPORATION COMMISSION

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COMMISSIONERS

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JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
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KRISTIN K. MAYES
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AZ CORP COMMISSION
DOCUMENT CONTROL

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827

ARIZONA CORPORATION COMMISSION STAFF'S POST HEARING BRIEF

January 22, 2007

Arizona Corporation Commission
DOCKETED
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DOCKETED BY nR

Christopher C. Kempley, Chief Counsel
Janet Wagner, Senior Staff Counsel
Charles Hains, Attorney
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

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I. INTRODUCTION

Arizona Corporation Commission Staff ("Staff") hereby files its opening brief in this matter. This brief primarily attempts to identify and explain all issues and/or positions adopted by Staff in this proceeding. Although this brief also attempts to anticipate and respond to other parties' criticisms of those positions, Staff intends to address the majority of such criticisms in its responsive brief, currently due on February 5, 2007.

II. THE COMMISSION SHOULD REJECT APS' PROPOSED "ATTRITION ADJUSTMENTS," WHICH ARE BOTH MERITLESS AND UNTIMELY RAISED.

APS criticizes Staff for failing to perform an analysis of the likely consequences of its overall revenue requirement recommendation. (Dittmer Surrebuttal Test., hereinafter referred to as "Dittmer Surrebuttal," Ex. S-34 at 4). APS concedes a number of adjustments, but advocates for an "attrition adjustment" that would make up on a dollar-for-dollar basis the sum of any Staff, RUCO, or intervener adjustments that the Commission might adopt. (Dittmer Direct Test., hereinafter referred to as "Dittmer Direct," Ex. S-34 at 4; Tr. at 4264-65). The basis of this request is APS' financial forecasts for 2006, 2007, and 2008, which allegedly indicate that the Company must receive all of its rate request in order to retain its investment grade credit rating. (Dittmer Surrebuttal at 4-5). Staff urges the Commission to entirely reject APS' various requests for so-called "attrition adjustments" for the reasons discussed below.

A. APS' Initial Testimony And Exhibits Were Not Developed Based Upon Financial Integrity Issues.

APS' rate application is based upon an adjusted historic test year ending September 30, 2005. (Dittmer Surrebuttal at 5). The nature of this filing is consistent with the majority of APS' prior rate cases: not since the completion of Palo Verde has APS requested rate relief based upon financial integrity issues. *Id.* at 5-8. Until the Company filed its rebuttal testimony, there was no reason to assume that the present case was any different. *Id.* at 5.

In Staff's view, this rate case has been driven primarily by rising fuel and purchased power costs and by issues concerning the mechanics of the Company's existing Power Supply Adjustor ("PSA"), which imposes restrictions upon the timing and recovery of fuel and purchased power costs. *Id.* at 6. Staff has therefore devoted extensive resources to evaluating the reasonableness of proposed fuel and purchased power cost increases and to reviewing the mechanics of the existing PSA. *Id.* at 6-7. Given the nature of the Company's original rate case filing, this resource allocation was reasonable.

During the construction of Palo Verde, APS occasionally sought rate relief based upon financial integrity issues. *Id.* at 5. Those cases, however, clearly identified the basis for the rate request within the original filings. *Id.* In the present case, APS has essentially "laid in wait," allowing Staff and the other parties to expend considerable time and resources evaluating its proposed adjusted historic test year cost of service before switching the basis for its request virtually in mid-stream. (*See* Dittmer Surrebuttal at 7, 13). If the Commission were to adopt APS' specific "attrition adjustments"—requests that first arose in APS' rebuttal—it will encourage this utility as well as other Arizona utilities to adopt similar tactics in the future. APS will conclude that it can hold its "real case" in reserve until rebuttal, when opportunities for discovery and analysis are severely limited. This practice is unfair, and the Commission should not reward APS for this behavior, but should instead expressly disregard APS' untimely request for "attrition adjustments."

B. The Commission Should Be Wary Of Relying Upon The Company's Unaudited Forecasts.

The Commission should not rely on the Company's forecasts as a basis for determining rates. (Dittmer Surrebuttal at 8). Arizona is an historic test year jurisdiction. Both Commission regulations and applicable case law would appear to foreclose APS' attempts to achieve rates based upon a future test year.

APS' forecasts are also not as reliable as they would be if they had been subjected to typical rate case scrutiny. Staff and the other parties did not know until late in the proceeding that the Company planned to assert a request for rate relief based upon rationales other than an historic test year. Therefore, the forecasts presented by the Company have not received the level of review necessary to determine the extent of their accuracy or reliability. *Id.* at 7-10.

For example, APS' forecasts appear to be based on "total company" earnings, including data related to APS' transmission operations. (Dittmer Supplemental Test., Ex. S-39 at 8-9). Therefore, it is not clear to what degree any alleged earnings shortfall is related to a potential need for transmission rate relief. *Id.* at 9.

Just as mistakes and oversights occurred in the preparation of APS' original case, it is entirely possible that mistakes and oversights occurred in the preparation of APS' financial forecasts. *Id.* at 10. Even in the absence of actual errors, forecasts can be prepared with results skewed toward pessimistic or optimistic results. *Id.* If the Commission were to base APS' rates upon these forecasts—which were provided late in the proceeding, thereby precluding the parties from performing a meaningful review—APS will be encouraged to repeat these tactics. The Commission should not allow APS to benefit by these manipulations of the rate case process.

<u>C.</u> <u>The Commission Should Recognize The Significant Advantages To APS' Shareholders Inherent In The *Existing* PSA.</u>

The inclusion of demand charges in APS' PSA is a substantial benefit to APS in its efforts to address attrition. (Dittmer Surrebuttal at 11). Earnings attrition occurs when the increase in the cost of providing service begins to outpace the increase in margins from growth in sales. *Id.* at 10. APS is experiencing and probably will continue to experience high growth in retail sales. *Id.* at 11. This growth creates a need to add transmission and distribution plant and to find new sources of generation capacity and energy. *Id.* At least until the expiration of the self-build moratorium established in Decision No. 67744, APS will probably meet the need for new generation capacity and energy through purchased power agreements. *Id.*

APS' existing PSA permits APS to pass through not only energy charges but also demand charges. *Id.* The purchased capacity paid for through the demand charges replaces the need to build generating capacity that would otherwise be required to meet customer growth. *Id.* It is worthwhile and significant to note that demand charges are not always included in fuel adjustment clauses. *Id.* Specifically, demand charges are often excluded from such clauses because growth in retail sales will often be available to offset or "pay for" the incremental demand costs incurred to serve new load. *Id.*

Staff is not suggesting that demand charges should be excluded from APS' PSA; Staff merely raises this issue to point out that APS' PSA is more beneficial to shareholders than many fuel adjustment clauses. *Id.* Because any attrition related to production costs is significantly addressed through the recovery of demand charges in the PSA, growth in retail margins is available to a much larger extent to meet cost increases related to growth in distribution plant and to recover cost increases caused by inflation over time. *Id.* at 12. This feature of APS' *existing* PSA significantly undermines APS' claim that it will suffer "attrition."

D. APS' Request For "Attrition Adjustments" Is Without Merit And Should Be Rejected.

Staff urges the Commission to reject APS' requested "attrition adjustments" at this time. Although such adjustments were sometimes granted in the timeframe of the late 1970s through early 1990s, the circumstances that supported attrition adjustments in those cases are not present in this case. (Dittmer Surrebuttal at 18). For example, interest rates and inflation rates are but a fraction of what they were in the early 1980s. *Id.* Although APS forecasts a need for significant construction expenditures for transmission and distribution, it does not have plans to construct a new generating facility. *Id.* Pursuant to Decision No. 67744, APS is foreclosed from constructing new generating facilities absent Commission approval. *Id.* at 18-19.

Furthermore, the need for a base rate increase in this case is entirely driven by increased fuel and purchased power expenses. *Id.* at 19. Specifically, Staff recommended an overall base rate increase of $191.4 million, which includes an increase in fuel and purchased power costs of $193.5 million. *Id.* Thus, outside of fuel and purchased power costs, APS' cost of service has been—and continues to be—adequately recovered within existing base rates. *Id.*

Finally, Staff is recommending significant modifications to the existing PSA. Staff is recommending the elimination of the 90/10 sharing mechanism, which contributed to some degree to APS' cash flow constraints and earnings shortfalls. *Id.* Staff is also recommending a "forward component" for the PSA, which will serve to set the adjuster rate based upon forecasts that are closer in time to the period in which fuel and purchased power costs will be incurred. *Id.* at 19-20. If these and other modifications are adopted, the likelihood of cash flow constraints due to delays in recovery of fuel and purchased power costs should be significantly diminished. *Id.* at 19.

Staff believes that any "attrition" that may have occurred was related to the delay in the recovery of fuel and purchased power costs. *Id.* at 20. If Staff's PSA recommendations are adopted, attrition caused by such delay should be virtually eliminated. *Id.* Given current conditions of low inflation, low interest rates, experience with APS' existing PSA, and Staff's proposed changes to the PSA, "attrition adjustments" are not necessary at this point in time, and the Commission should reject them. *Id.*

E. If The Commission Were Inclined To Adopt—Over Staff's Objection—Any Of APS' "Attrition Adjustments," It Should Adopt Either The CWIP Proposal Or The Accelerated Depreciation Proposal.

If the Commission were inclined to adopt an "attrition adjustment," it should at least choose an alternative that will eventually be credited to ratepayers. Both the CWIP proposal and the accelerated depreciation proposal affect the recovery period for fixed assets. (Dittmer Surrebuttal at at 16). Each of these two proposals results in accounting changes that will eventually yield reductions in rates for future ratepayers. *Id.* at 16-17.

The other "attrition adjustments" proposed by APS have no associated accounting changes; thus, the revenues collected under those proposals would flow to APS' "bottom line," resulting in increased earnings for shareholders but failing to produce any direct benefit to ratepayers. *Id.* at 17. At least the CWIP proposal and the accelerated depreciation proposal would eventually provide benefits to future ratepayers.

F. If APS Wishes To Seek "Attrition Adjustments" In Future Cases, The Commission Should Require APS To Specifically Set Forth The Relief That It Requests In Its Initial Filing.

If, in the future, APS wishes to propose an attrition adjustment or any other unique rate proposal that is driven by forward-looking financial metrics, it should be required to make such requests within its initial direct filing so that Staff and other parties are appropriately forewarned and can efficiently allocate resources. (Dittmer Surrebuttal at 17). The Commission should issue a specific and express statement to that effect in this case.

APS should not be permitted to make significant requests based upon new arguments for the first time in the rebuttal phase of its case. *Id.* Staff and other parties had less than two weeks to respond in surrebuttal to APS' rebuttal; accordingly, there was insufficient time to undertake discovery or perform meaningful analysis of APS' new proposals. *Id.* It is simply unfair to allow such behavior from APS, and the Commission should ensure that such tactics are not repeated.

III. THE COMMISSION SHOULD ADOPT STAFF'S PROPOSED BASE COST OF FUEL AND PURCHASED POWER

In its direct case, APS used normalized, projected 2006 data to form the basis for its proposed base cost of fuel and purchased power. (Antonuk Direct Test., hereinafter referred to as "Antonuk Direct", Ex. S-28 at 4-5, 26). Staff reviewed APS' proposal and concluded that calendar year 2006 serves as an appropriate period from which to establish the fuel and energy portion of APS' base rates. *Id.* at 26. Staff proposed a number of adjustments to the 2006 data in order to arrive at its calculation for net retail fuel costs: $824.4 million, which results in an average fuel cost of 2.8104 cents/kWh. *Id.* at 5-6, 26-32. Based upon this calculation, Staff concluded that APS' proposed base cost of fuel and purchased power should be reduced by $111.6 million (with the APS sharing proposal) or $111.4 (without the APS sharing proposal). *Id.* at 33. It should also be reduced by a further $3,702,501 to reflect 2006 margins for transactions involving non-utility use of an APS transmission asset. *Id.* at 29-30, 33. Finally, it should be reduced further to account for the removal of non-fuel and energy costs associated with non-utility marketing and trading activity. (Antonuk Direct at 33; Dittmer Direct at 59-61).

Instead of responding to the adjustments that Staff and others proposed in direct testimony, APS' rebuttal abandoned its use of a 2006 forecast and instead substituted a 2007 forecast. (Ewen Rebuttal at 4-6; Antonuk Surrebuttal, hereinafter referred to as "Antonuk Surrebuttal", Ex. S-29 at 2-3). Staff opposes the use of APS' 2007 forecasts (provided in APS' rebuttal and rejoinder) as the means for determining the base cost of fuel and purchased power. (Antonuk Surrebuttal at 8-10). As Staff witness Antonuk's direct testimony describes, Staff thoroughly analyzed APS' originally proposed base cost of fuel and purchased power, which was based upon calendar year 2006. (Antonuk Direct at 26-33). By contrast, the 2007 forecasts, which were provided relatively late in the proceeding, have not undergone the same level of Staff scrutiny as the 2006 forecast presented in APS' original case. (Antonuk Surrebuttal at 8-10). These forecasts are complex to perform, and they are subject to both judgment and error. *Id.* at 8-9. In fact, the potential for error is demonstrated by APS' testimony, which contained at least two significant errors. *Id.* at 9. For these reasons, the Commission should adopt Staff's recommended base cost of fuel and purchased power to determine APS' base rates.

IV. THE COMMISSION SHOULD REJECT APS' PROPOSED PENSION EXPENSE ADJUSTMENT, WHICH WOULD INCREASE TEST YEAR PENSION EXPENSE BY APPROXIMATELY $44 MILLION.

In her direct testimony, APS witness Rockenberger claims that, as of December 31, 2004, the Company's actuaries had calculated a projected benefit obligation of $1,371 million. (Dittmer Direct at 62). She also states that, as of December 31, 2004, the "market value" of the assets in the external pension trust was approximately $982 million. *Id.* According to Ms. Rockenberger, the difference between these two figures leaves approximately $389 million of the projected pension obligation "underfunded." *Id.* Because Pinnacle West Capital Corporation and other entities are responsible for approximately 39% of this underfunded amount, APS has proposed recovering from ratepayers the remaining 61% (approximately $218 million) over a five year period. *Id.* The $218 million figure divided by the five year amortization period results in APS' requested adjustment of $44 million. *Id.* Staff opposes this adjustment.

<u>A.</u> <u>The Commission Should Reject APS' Proposed Five-Year Amortization Of The Underfunded Projected Benefit Obligation.</u>

1. The magnitude of APS' projected benefit obligation is not highly unusual and should not be alarming.

Although it is not desirable for the projected benefit obligation to become significantly under or over funded relative to the current market value of plan assets, APS' "underfunded" position is not unusual, nor is it a situation that requires concern. (Dittmer Direct at 64-65). APS' "underfunded" position is primarily attributable to 1) the under-performance of returns on plan assets over a short period and 2) a significant increase in the calculated projected benefit obligation that is directly linked to the FAS 87 requirement to use a conservative interest rate for purposes of discounting the future obligation. *Id.* at 71-73, 81. In recent years, interest rates have fallen. A return to more "normal" interest rate levels would reduce the net present value of the projected benefit obligation and, in turn, the "underfunded" position. *Id.* at 72, 81. In addition, a short-term rally in the stock market could result in greater than expected returns on plan assets, which would also serve to narrow the gap between the market value of plan assets and the projected benefit obligation. *Id.* at 81.

The point to emphasize is that the difference between the market value of pension plan assets and the projected benefit obligation will vary—even significantly—over time. *Id.* These circumstances are not unusual and do not support the drastic and completely unprecedented proposal requested by APS. *Id.* at 81-82.

2. *The "underfunded" position of the projected benefit obligation is already considered within the development of APS' test year cost of service.*

To a large extent, the "underfunded" position of the projected benefit obligation is already considered within the net periodic pension cost and test year pension expense, which are both elements used to develop APS' cost of service. (Dittmer Direct at 65). To add an additional pension amortization expense, as APS proposes, could lead to a double collection of these expenses. (Dittmer Direct at 65; Dittmer Surrebuttal at 26-29).

When the return on plan assets falls short of expectations or when the current estimate of the projected benefit obligation exceeds prior projections, FAS 87 requires net periodic pension cost to include an amortization of significant shortfalls from earlier projections. (Dittmer Direct at 79-80, 82). The 2005 total net periodic pension cost (before allocation to APS' retail operations) was $62,797,000, which includes $19,801,000 attributable to the amortization of the shortfalls from earlier projections. *Id.* at 82. Thus, nearly a third of net periodic pension cost for 2005 consisted of this "catch up" amortization. *Id.* at 80, 82.

APS witness Brandt asserts that APS' pension trust did not "underperform" relative to the overall stock market. (Dittmer Surrebuttal at 26). While this may be true, it was never a point suggested by Staff and is completely irrelevant to the resolution of this issue. In his direct testimony, Staff witness Dittmer stated that APS' trust balance declined between 2001 and 2003, and he acknowledged that this decline is not surprising when one considers the *overall performance of the stock market* during this timeframe. *Id.* Contrary to APS' implications, the basis of Staff's opposition to the Company's pension expense is not that APS should be penalized for the underperformance of its pension trust. *Id.* Instead, Staff's testimony simply acknowledges that projections of pension trust performance are often unachieved in the short run and that significant differences are considered within the "catch-up" provision of FAS-87 determined net periodic pension costs. *Id.* at 27.

In the past, the Commission has developed the retail cost of service for APS by using FAS 87-determined net periodic pension cost and related net pension expense. (Dittmer Direct at 82). Whenever retail rates are based upon FAS 87-determined pension expense, such rates will include the "catch up" amortization designed to "correct" for 1) the impact of returns that are either significantly below or above previous estimates or 2) the growth or decline in the projected benefit obligation that is either above or below prior projections. *Id.* at 83. Consequently, APS' request to recover the "underfunded" projected benefit obligation over five years duplicates the recovery of such shortfall that already occurs when retail rates are developed by considering net periodic pension cost, which in turn includes the "catch-up" amortization. (Dittmer Direct at 83; Dittmer Surrebuttal at 37).

3. The Company's proposal is likely to lead to intergenerational inequities between existing and future ratepayers.

The projected benefit obligation considers future years of employment and future pay raises. (Dittmer Direct at 67-69, 83; Tr. at 423-24, 427-29). Under APS' proposal, ratepayers would be required to pay 1) the FAS-87 determined pension expense (including the "catch up" amortization) *and* 2) a five-year amortization of the "underfunded" pension benefit obligation. (Dittmer Direct at 84). Specifically, under the Company's proposal, retail rates would include not only test year actual pension expense of $23,484,000 but also the amortization of the "underfunded" projected benefit obligation of $43,695,000. *Id.* at 84, n. 29.

The Company's proposal essentially "front loads" future pension costs to existing ratepayers. *Id.* at 84. If the Commission were to adopt APS' proposal, future ratepayers would likely pay little, if any, pension expenses in rates after completion of the five-year amortization period. *Id.* Because future ratepayers will benefit from the services yet to be provided by APS employees in future years, it is inequitable to impose those costs on today's ratepayers. *Id.*

4. APS' proposal is inconsistent with regulatory precedent.

APS has not identified a single instance in this or any other jurisdiction in which a regulatory commission has adopted a proposal similar to the one proposed here. (Dittmer Direct at 84-85). Staff witness Dittmer, who has over thirty years of experience in processing rate cases, stated that he is not aware of "a single instance where a regulatory commission has adopted the amortization proposal presented by APS" in this case. *Id.* at 85.

5. It is not clear that funds collected from ratepayers on an accelerated basis would actually be contributed to the pension fund to reduce the current gap between the market value of the pension fund assets and the projected benefit obligation.

In discovery, Staff asked APS to confirm that it intends to use the funds collected through its five-year amortization proposal to actually make additional contributions to the pension fund. (Dittmer Direct at 86). APS' response noted that "[t]he funding decision will depend upon the minimum pension funding requirements and IRS maximum tax deduction limitations. This may or may not require the full $44 million to be contributed to bring the fund to an approximate 100% funded status." (Dittmer Direct at 74-76, 86 (quoting APS' Resp. to Data Request UTI-2-137)). Later, APS clarified that it intends to commit to funding $44 million *more than it would have otherwise contributed* to the pension trust as long as the resulting contribution amount does not exceed the IRS maximum. *Id.* at 86.

APS' statements, however, are not sufficient to satisfy Staff's concerns. First, it will be impossible in the future to know what APS *might have contributed* to the pension fund absent the approval of its request for accelerated recovery. *Id.* at 87. In recent years, APS' actual pension fund contributions have differed significantly from the actuary's calculations of net periodic pension costs, and APS' contributions were always less than the maximum contribution allowed by the IRS. *Id.* at 75-76, 80, 87. Since APS' last rate case, APS did not fund its pension trust in an amount equal to what it was permitted to collect for pension costs in rates. *Id.* at 87.

In rebuttal, APS witness Brandt states that APS' pension contributions have actually exceeded net periodic pension costs over the past five years and that Staff witness Dittmer's claims to the contrary are incorrect. (Dittmer Surrebuttal at 37). In surrebuttal, Mr. Dittmer acknowledged that his calculations were off by one year and therefore incorrect. *Id.* at 38. This error, however, does not affect the validity of Mr. Dittmer's underlying premise, *i.e.*, that APS' contributions in recent years have been less than its net periodic pension cost. *Id.*

Notwithstanding the corrections set forth in Mr. Brandt's testimony, the Company's contributions to the external pension fund were less than its net periodic pension cost for years 2003 and 2004. *Id.* It would be reasonable to expect APS to make contributions to the pension trust that are at least equivalent to the net periodic pension cost used to establish retail rates before asking ratepayers to fund an accelerated recovery. (Dittmer Direct at 87; Dittmer Surrebuttal at 38).

6. Implementation of APS' proposal will lead to other intergenerational equity issues because some of the "underfunding" is related to payroll dollars being capitalized as well as expensed.

The level of *net periodic pension cost* that is calculated by the Company's actuaries pertains to total payroll costs incurred within a given reporting period whether or not such costs are *expensed* or *capitalized*. (Dittmer Direct at 88). By contrast, the amount of *pension expense* recorded within a given reporting period relates to costs *expensed* during that same reporting period. *Id.* For ratemaking purposes, only *pension expense* associated with payroll dollars *expensed* are included within the test year cost of service. *Id.*

APS proposes to collect (in rates over a five-year amortization period) an amount that is designed to recover a point-in-time calculation of the difference between the projected benefit obligation and the market value of the pension trust assets. *Id.* However, a portion of such difference is related to payroll dollars that will be *capitalized* to plant in service. Like other capitalized items (contractor labor, materials, supplies, interest, etc.), such costs will be included in plant in service and will be recovered from ratepayers in depreciation expense. Ratepayers who benefit from long-lived plant assets should pay for such facilities over the term of the assets' useful lives. *Id.* The Company's proposal, however, would charge the underfunded pension amount entirely to existing ratepayers, thereby ignoring that a portion of those costs should be capitalized. *Id.* This result will lead to further intergenerational inequity among ratepayers because current ratepayers will pay on an accelerated basis costs that should instead be capitalized as plant in service. *Id.* at 89. If these costs were appropriately capitalized to plant in service, future ratepayers would bear these costs by paying depreciation expense as well as a return. *Id.*

7. There is no evidence to suggest that the significant increase in costs that APS proposes to pass on to ratepayers at this time will eventually lead to long-term savings for ratepayers.

If the Company could establish that accelerated recovery of a given expense will provide subsequent ratepayer savings, that argument might support the Company's proposal. Although Staff asked the Company to estimate the amount of pension expense savings that could be achieved if its proposal were adopted, APS was unable to identify any savings. (Dittmer Direct at 89).

8. APS' proposal will tend to worsen APS' cash flow position both now and in the future.

An examination of the mechanics of APS' proposal shows that it is actually harmful to the Company's interests. Specifically, APS' proposal will not alleviate APS' current cash flow position and will very probably exacerbate APS' future cash flow position.

APS' proposal will do absolutely nothing to improve APS' cash flow position *in the short term*. APS has stated that it intends to fund the external pension trust with the incremental pension recovery that it has requested in rates. If the Commission were to grant APS' request, APS would purportedly contribute to the external pension trust that portion of its rates that is related to pension expense. In other words, every additional dollar that APS might collect in rates (related to its five-year accelerated recovery of pension expense) would in turn be used to fund its external pension trust.

Because every additional dollar collected in rates would be offset by a contribution to the external trust, APS' current cash flow position would not be improved. (Dittmer Surrebuttal at 32-33, 39).

In addition, accelerated recovery of pension expenses will very likely exacerbate APS' *future* cash flow position. APS has acknowledged that accelerated recovery of its pension expense will require the creation of a regulatory liability in order to refund to ratepayers the over-recovery of pension expense collected in years 1-5. *Id.* at 29-30. When the regulatory liability comes due (years 6-15 of APS' proposal), the Company will have to *simultaneously* fund its ongoing construction program to meet customer growth *and* refund the regulatory liability. *Id.* at 30-33.

As Staff witness Dittmer explained, funds that are contributed to an external pension trust cannot be withdrawn except to meet payment obligations to retirees. Because APS will not be able to withdraw money from the trust, it will have to refund the regulatory liability with funds from other sources, such as internally generated funds or borrowed money. *Id.* at 30-33. These circumstances will only *worsen* APS' cash flow position at a time when it anticipates continued new construction as a result of continued customer growth.

These factors demonstrate that APS' pension expense proposal provides no benefits to either ratepayers or APS. There is no merit to this proposal, and the Commission should reject it.

B. APS' Proposed Increase To Test Year Pension Expense In Conjunction With Its Payroll Annualization Adjustment

In addition to APS' proposal to amortize the underfunded pension benefit obligation, the Company has also proposed to increase test year pension expense in connection with its payroll annualization adjustment. (Dittmer Direct at 63). After annualizing payroll costs to reflect 1) the number of employees at the end of the test year and 2) wage increases granted through April of 2006, APS applied a benefits loading rate to the payroll annualization adjustment to reflect claimed increases in pension expense, post retirement medical benefits, health/medical costs, and payroll taxes. *Id.*

Staff accepted the Company's assumption that increased payroll costs lead to increases in both payroll taxes and health/medical costs for active employees. *Id.* However, Staff rejects the assumption that payroll increases also lead to increases in pension expenses and post retirement medical expenses, and has therefore reversed this adjustment. *Id.* at 63-64.

C. Summary

Staff reversed APS' proposed five-year amortization of the underfunded pension benefit obligation. (Dittmer Direct at 62, 64). Staff also subtracted the pro forma level of pension expense that APS had included as part of its payroll annualization adjustment. *Id.* at 63. Finally, Staff believes that the Commission should set rates in this proceeding based upon the Company's 2006 pension expense as reported in the Company's 2006 actuarial study. *Id.* at 63-64, 89-90. In rebuttal, APS agreed with this update and proposed an adjustment to reflect 2006 actuarially determined pension costs. Staff, in turn, incorporated this adjustment in its updated schedules. (*See* Ex. S-38).

V. CASH WORKING CAPITAL

A. Overview

Cash working capital is defined as the amount of cash needed by a utility to pay the day-to-day expenses incurred in providing service as compared to the timing of the utility's collection of revenues for those services. (Dittmer Direct at 33). In other words, if the timing of a company's cash expenditures precedes its cash recovery for those expenditures, investors are providing the cash working capital. *Id.* at 33, 35, 36. By contrast, if ratepayers' payments for utility service precede the company's cash disbursements for expenses, ratepayers are providing the cash working capital. *Id.* at 33, 36. Cash working capital is typically included in a utility's rate base in order to recognize these timing issues related to cash flow. *Id.* at 34. Cash working capital can be either a positive or a negative value, and a negative result should not be surprising or troublesome. *Id.* at 32, 33, 34. In fact, both Staff and APS have proposed *negative* allowances for cash working capital in this case.

APS has proposed a rate base *deduction* of $29.1 million for cash working capital based upon the results of a company-prepared lead lag study[1] for APS' Arizona retail operations. (*See* Dittmer Direct at 25, 34, 35). By contrast, Staff increased the amount of APS' proposed deduction thereby resulting in a larger *negative* cash working capital allowance than that proposed by APS. *Id.* at 25, 31, 32. In quantifying Staff's cash working capital adjustment, Staff did not prepare a stand-alone lead lag study, but instead analyzed, tested, and proposed corrections to the lead lag study prepared by APS. *Id.* at 30, 34.

B. APS' Lead Lag Study Fails To Satisfy Applicable Commission Precedent.

APS' proposed lead lag study includes non-cash items—such as depreciation expense, amortization expense, and deferred income tax expense—and fails to consider interest expense, thereby significantly overstating the Company's cash working capital requirements. (Dittmer Direct at 27, 28, 29, 30, ...). This approach is inconsistent with longstanding Commission precedent:

> We have repeatedly rejected the inclusion of deferred taxes and depreciation in the calculation of current cash working capital requirements. We have also finally concluded that interest expense should be included in a lead/lag study, and we have expressly approved the concept of negative cash working capital.

Decision No. 55931 at 66. Curiously, APS recognizes this precedent in its January 31, 2006 rate case filing, wherein APS Witness Rockenberger included the following statements:

> I am testifying to all of the data in SFR Schedule B-5, with the exception of the Working Capital calculation (line 1 of page 1), which Mr. Fred Balluff will address. My testimony presents the calculation of the allowance for working capital, *which includes a cash working capital component determined using the lead/lag study methodology required by Decision No. 55931.*

(Rockenberger Direct Test., Ex. APS-56 at 27 (emphasis added); *see also* Dittmer Direct at 28). Despite this assertion, it is undisputed that APS' proposed lead lag study does not comply with the requirements of Decision No. 55931, *i.e.*, it does not exclude depreciation expense, amortization expense, and deferred income tax expense, and it fails to include interest expense. (Dittmer Direct at

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[1] A lead lag study systematically measures the timing of cash flows through the utility. (Dittmer Direct at 35).

28-29; Tr. at 2662-64). The rate base impact of APS' failure to prepare its lead lag study in accordance with Commission precedent overstates cash working capital, and therefore APS' rate base, by approximately $43.6 million. (Dittmer Direct at 39).

C. The Commission Should Exclude Non-Cash Items From APS' Lead Lag Study.

In considering this issue, it is helpful to review the definition of cash working capital: cash working capital is defined as the amount of cash needed by a utility to pay the day-to-day expenses incurred in providing service as compared to the timing of the utility's collection of revenues for those services. (Dittmer Direct at 33, 36). Therefore, the particular cash flows that appropriately fall within the scope of a lead lag study are those transactions that relate to the *day-to-day payment* of expenses incurred in providing utility service. *Id.* at 36, 37.

Neither depreciation expenses nor deferred income tax expenses requires APS to make a cash outlay in order to meet its day-to-day expenses incurred in providing utility service. Both depreciation expenses and deferred income tax expenses are non-cash expenses; both represent accrued expenses; both are recovered through utility rates; the cumulative recoveries of both expenses are recognized as zero cost capital and used to reduce rate base; neither involves current period payments to suppliers, vendors, or taxing authorities; and both provide a source of cash (in other words, positive cash flow) that can be used for investment in plant construction or other corporate activities. *Id.* at 41-42. As Staff witness Dittmer explained in his direct testimony,

> [including non-cash expense items in a lead lag study] would be inconsistent with the widely accepted view of cash working capital as the amount of invested capital required to bridge the gap between the *payment* of cash expenses and the *collection* of related revenues. When there is no expense payment, no cash working capital is required. Depreciation and deferred income tax expenses do not require current period cash payments. Since investors are not required to provide cash advances for these expense items prior to the collection of revenues, it would be improper to include such items in a study of cash working capital requirements.

. . .

Id. at 42 (emphasis in original). For these reasons, non-cash expenses, such as depreciation, amortization, and deferred income tax expenses, should be removed from the lead lag study in order to limit the study results to "cash" expense requirements. *Id.* at 30.

In rebuttal, APS witness Balluff claims that a lead lag study should include a lag for the collection of depreciation expense, because the recorded "accumulated depreciation" as of the end of the test year has not been fully collected from ratepayers at that point in time. This approach, however, expands the lead lag study to consider "cash" recovery of plant and depreciation reserve. (*See* Dittmer Direct at 39-40). Staff opposes this approach.

Although not every dollar of recorded depreciation reserve would have been collected from ratepayers as of the end of the test year, not every dollar of construction recorded as plant in service would have been "paid for" by the Company as of the end of the test year. (Dittmer Direct at 39-40; Dittmer Surrebuttal at 46). Further, as Staff witness Dittmer explained, every dollar of the depreciation reserve recorded at the end of the test year will have been recovered from ratepayers by the time rates become effective in this case. (Dittmer Direct at 40).

APS witness Balluff has not raised new arguments. These arguments have been presented—and rejected—in previous Commission rate cases. Those outcomes should be reaffirmed in this case.

D. The Commission Should Include Interest Expense In APS' Lead Lag Study.

Interest expense is a direct result of the Company's debt obligations. (Dittmer Direct at 43). Each debt issue requires the periodic cash payment of interest expense in known amounts that become due at specific points in time, *e.g.*, in quarterly or semi-annual payments. *Id.* The ratemaking formula provides for the recovery of these periodic payments to debt holders. *Id.* Because ratepayers pay for service on a monthly basis and because these periodic payments to debt holders typically occur quarterly or semi-annually, the lead lag study should recognize the Company's use of these funds for the extended period between their collection from ratepayers and the Company's payout of interest to debt holders. *Id.*

<u>E.</u> <u>Staff Also Incorporated Certain Adjustments To APS' Lead Lag Study That APS Has Conceded.</u>

Staff's proposed adjustments to APS' lead lag study include the following corrections: 1) Staff revised the purchased power expense level to reflect the elimination of significant unregulated power marketing activity from the quantification of cash working capital; 2) Staff recalculated the composite revenue lag using test year revenues, instead of 2004 revenues, thereby adopting a re-weighting method that is consistent with the preceding purchased power expense adjustment; 3) Staff restated APS' expense lag calculation regarding the Palo Verde lease to reflect a shift in semi-annual payment requirements that began in 2005; and 4) Staff revised the payment lag for Arizona state taxes to be consistent with the statutory payment due dates. (Dittmer Direct at 30-31). Staff believes that APS has accepted these corrections.

VI. SUNDANCE UNITS' MAJOR OVERHAUL COSTS

APS has included in its cost of service the operations and maintenance ("O&M") expense associated with its recently acquired Sundance Combustion Turbine Units ("Sundance"). (Dittmer Direct at 95). Although Staff conceptually agrees that it is appropriate to recognize Sundance O&M expenses in APS' rates, Staff disagrees with certain specific estimated O&M expenses requested by APS in this case. *Id.* Specifically, Staff opposes the recovery of certain estimated Sundance O&M expenses that will not actually be incurred for many years into the future. *Id.*

As part of its Sundance O&M proposal, APS includes $2.75 million for "non-routine" maintenance expense. *Id.* at 96. These "non-routine" maintenance activities are broken out between "Hot Gas Paths" and "Major" overhauls. *Id.* The Hot Gas Path overhauls are scheduled to occur at 18,000 usage-hour intervals, and the Major overhauls are scheduled to occur at 36,000 hour intervals. *Id.* at 96-97. On average, each Sundance combustion turbine is predicted to run approximately 1,500 hours per year. *Id.* at 97. Therefore, assuming average annual hours of usage for each unit, the average interval between Hot Gas Path overhauls is approximately twelve years, and the average interval between Major overhauls is approximately twenty-four years. *Id.* Initially, APS intends to unevenly run the Sundance units so that some units will reach the usage intervals for these types of overhauls earlier than other units, thereby staggering the overhaul cycle and avoiding the need to overhaul all ten units at the same time. *Id.*

Notwithstanding this staggered overhaul cycle, the Company's adjustment will capture the costs of events that will not occur for many years into the future and that are unlikely to occur during the time when rates established in this proceeding will be in effect. (Dittmer Direct Confidential Version, Ex. S-36 at 97). For these reasons, Staff opposes this element of APS' Sundance O&M adjustment and urges the Commission to reject it. *Id.*

Because these non-routine maintenance activities are related to hours of usage, there is some conceptual support for beginning to accrue for costs that are expected to be incurred in the future but are related to usage experienced today. *Id.* at 98. The danger associated with such a practice is that ratepayers could be overcharged, paying for these O&M expenses once today as estimates and then again in the future when they are actually incurred. *Id.* at 98-99. Unless the cost for future expenses being recovered in today's rates are specifically accrued on the Company's balance sheet for consideration in future rate proceedings, there is a high probability that ratepayers will be "double charged" for such expenses. *Id.* at 98. APS has indicated in discovery that it has no intention of undertaking a specific accrual for these expenses to ensure that they will be considered in future rate proceedings. *Id.*

This high probability for overcharging such costs is related to the way that APS has typically normalized maintenance costs for its *mature* generating units. *Id.* In this current case and in previous cases, APS has proposed to normalize maintenance costs for mature generating units by calculating a multi-year historical average of maintenance costs, adjusted for inflation over time, to arrive at a normalized level of maintenance expense. *Id.* This method tends to smooth the somewhat uneven and significant costs of major planned overhauls and other non-routine events. *Id.* at 98-99. If this method continues to be used in the future, the Sundance costs for non-routine maintenance activities—once they are actually incurred—presumably will be considered in the multi-year averaging process described above. *Id.* at 99. At that point in time in a future rate case, it is very likely that ratepayers will again be charged for costs that they have already paid, unless regulators have some means to reconsider the issue. *Id.* It is important to note that this issue would not occur until many years into the future. *Id.* at 97, 99.

APS has implied that Staff's approach to maintenance expense for the Sundance units is inconsistent to its approach to maintenance expense for the PWEC units. (Tr. at 4223). In both its last rate case and this current rate case, APS proposed to include in its cost of service a multi-year projection of PWEC's non-fuel and maintenance expense, and Staff has accepted this proposal in both cases. Staff's acceptance of APS' proposal regarding PWEC is not relevant to determining the appropriate level of maintenance expense for the Sundance units.

Although APS used a forecast to develop its cost of service proposals for both PWEC and Sundance, there are significant factual distinctions between the PWEC units and the Sundance units. *Id.* at 4223-24. Staff accepted the non-routine maintenance included in the PWEC forecast because that maintenance had already occurred. *Id.* By contrast, the Sundance non-routine maintenance is not scheduled to occur until far into the future—well beyond the time that rates established in this proceeding will be in effect. *Id.*

If the Commission were to grant APS' request to begin recovery of these non-routine maintenance expenses, the Commission should at least require APS to recognize monies for non-routine maintenance collected within rates as a current period expense and to concurrently establish a regulatory liability on its balance sheet. *Id.* at 99. When these costs are eventually incurred, they could then be charged against the deferred liability account rather than being charged to maintenance expense, where they could otherwise be considered in developing future rates. *Id.* at 99-100.

Staff's primary recommendation on this issue is to entirely eliminate the non-routine portion of Sundance O&M expense from APS' cost of service. If, however, the Commission were to adopt the Company's request, it should also impose the accounting treatment discussed above. (Dittmer Direct at 100). This latter alternative is not an especially desirable approach, considering the value of this issue relative to other issues.

VII. OTHER MISCELLANEOUS ADJUSTMENTS

A. SFAS 112—Other Deferred Credits As A Rate Base Offset

Staff has proposed a rate base deduction of $3.67 million for the Accumulated Provision of SFAS 112 costs. (Dittmer Direct at 22). These SFAS 112 costs relate to payments to employees on long-term disability and are ultimately included in the above-the-line cost of service. *Id.* at 21. For this reason, it is appropriate to include these cost-free funds as a rate base offset. *Id.* APS has acknowledged that it is appropriate to include the end-of-test-year balance for the Accumulated Provision of SFAS 112 as a rate base offset, and APS has also acknowledged that it failed to include this item in its original case. *Id.*

B. Bark Beetle Remediation Costs

In APS' last rate case, the parties reached a settlement agreement, which was in large part adopted by the Commission. (Dittmer Direct at 22). That settlement agreement provided for APS to defer bark beetle remediation costs. *Id.* These costs relate to removing trees in northern Arizona that are located near transmission lines and that have died from bark beetle infestation. *Id.* The settlement agreement—and the resulting Commission order—do not provide for recovery of bark beetle remediation costs in rates, but they do authorize APS to defer for later recovery the reasonable and prudent costs of bark beetle remediation that exceed the prior test year level of tree and brush control expense. *Id.*

In this case, APS has proposed rate base inclusion of two categories of bark beetle remediation costs: those deferred on its books as of the end of the test year and those estimated to be incurred through the remainder of 2005 and 2006. *Id.* at 23. APS also seeks cost recovery in base rates of amortization expense designed to recover over a three year period the end-of-test-year-actual plus estimated-through-end-of-2006 deferred bark beetle remediation costs. *Id.*

There are aspects of the Company's treatment of the bark beetle issues that Staff does not support. First, Staff disagrees with APS' calculation of its bark beetle deferrals. After the Commission issued the last rate order in April of 2005, APS essentially began deferring bark beetle remediation expenditures retroactively to January 1, 2005 – three months before the effective date of that decision. *Id.* Decision No. 67744, which is APS' last rate order, does not give APS the authority to defer these costs prior to its effective date. *Id.* Therefore, the bark beetle remediation costs that relate to work undertaken between January 1, 2005 and March 31, 2005, *i.e.*, the period before the effective date of Decision No. 67744, should be removed from APS' proposed rate base. *Id.* In addition, a corresponding portion should also be removed from APS' amortization expense proposal. *Id.* These adjustments are reflected in Schedule B-2 in Staff Exhibit S-35.

Staff made two additional adjustments to APS' proposed bark beetle deferral balance, which APS has accepted. *Id.* at 24. When calculating its proposed pro forma rate base adjustment, APS started with its projected end-of-2006 deferral balance. *Id.* From that starting point, APS incorrectly subtracted the November 30, 2005 actual balance of recorded deferred bark beetle costs instead of correctly subtracting the September 30, 2005 historic test year ending balance. *Id.* In addition, APS failed to recognize related accumulated deferred income taxes as a reduction to its pro forma rate base adjustment. *Id.*

In summary, Staff's rate base adjustments on Schedule B-2 eliminate retroactive deferrals related to expenditures incurred prior to April 1, 2005; reflect related accumulated deferred income taxes; and correct for the problem of subtracting the incorrect balance of deferred bark beetle costs. *Id.* In addition, Staff's adjustments on Schedule C-14 reduce the amortization expense related to the deferrals of expenditures incurred before April 1, 2005. *Id.* Except for the adjustments related to the retroactive deferrals, APS has accepted Staff's proposed adjustments to bark beetle remediation costs.

In rebuttal, APS argues that Decision No. 67744 intends for the Company to be granted a full year of recovery. (Dittmer Surrebuttal at 40). APS also claims that the settlement agreement intends for bark beetle remediation deferrals to include the entire calendar year in which the deferral becomes effective. *Id.* Staff disagrees with these assertions. First, neither the settlement agreement nor Commission Decision No. 67744 expressly states this intent. *Id.* at 41. More importantly, the Company's argument assumes that a Commission order may be applied retroactively without the Commission expressly stating that it intends retroactive application. *Id.* The Commission should reject the Company's argument and accept Staff's proposed adjustment.

C. Adjustment For Lost Margins From DSM Programs

This adjustment to operating income reverses an adjustment posted by APS to reflect "lost" retail margins that it anticipates due to the implementation of various demand-side management ("DSM") programs. (Dittmer Direct at 58). Specifically, Staff recommends that the Commission disallow APS' proposed $4,907,000 pro forma adjustment to account for net lost revenue that the Company claims will result from DSM programs. (Anderson Direct Test., hereinafter referred to as "Anderson Direct", Ex. S-16 at 8). This adjustment is addressed in more detail in the Demand-Side Management section of this brief. (Section XIII).

D. Miscellaneous Adjustments To Other Revenues

Staff's adjustment to Schedule C-2 is a correction of APS' pro forma adjustment for Schedule 1 charges. (Dittmer Direct at 58). The correction is necessary to restate the transaction volumes to reflect actual test period data. *Id.* In addition, the adjustment removes expenses that APS expected in connection with its program to eliminate paper bills. *Id.* Specifically, APS never initiated a $5.00 incentive to attract subscribers to its paperless bill program because enrollment in this program has been strong even without the incentive. *Id.* at 58-59. Thus, Staff eliminated the estimated expense related to the $5.00 incentive. *Id.* at 59. APS has accepted these adjustments. *Id.* at 58-59.

E. Normalized Fuel Expense, Purchased Power Expense, And Off-System Sales Margins

The adjustment set forth in Schedule C-3 shows the pro forma level of fuel, purchased power expense, and off-system sales revenues and related expense that Staff believes should be used to develop base rates. (Dittmer Direct at 59). The pro forma levels for these items should also be used as the basis for the PSA factor. *Id.* This adjustment is addressed in more detail in the section of this brief that discusses Staff's proposed base cost for fuel and purchased power expense. (Section III).

F. Elimination Of Expenses Associated With Unregulated Marketing And Trading Operations

APS operates certain unregulated marketing and trading activities. (Dittmer Direct at 59). However, APS inadvertently included the revenues and expenses associated with these activities in the development of its test year cost of service. *Id.* at 60. During the test year, unregulated marketing and trading operations experienced a net loss of approximately $15 million. *Id.* Removing this net loss from test year operating results reduces APS' adjusted test year cost of service, thereby reducing the requested revenue increase. *Id.*

Staff's adjustment on Schedule C-5, which APS accepts, shows the elimination of marketing and trading operations and maintenance expense other than purchased power. *Id.* at 61. Staff Schedule C-4 shows a separate but related adjustment to eliminate marketing and trading off-system sales and revenues and related purchased power expense. *Id.* Thus, the net marketing and trading loss of $8,273,000 shown on Schedule C-4 plus the removal of non-purchased power operation and maintenance expenses shown on Schedule C-5 sum to the total before-tax loss of $15 million. *Id.*

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G. Post Retirement Medical Benefits Adjustment

Staff has recommended an adjustment to reflect ongoing post-retirement medical benefits ("PRMB") expense based upon the actuarial estimate that APS used to record PRMB expense for 2006. (Dittmer Direct at 90). For consistency as well as to incorporate last known changes for this significant employee benefit, Staff has proposed a PRMB adjustment calculated identically to Staff's adjustment for pension expense. *Id.* at 90-91.

H. Advertising Expense

APS has proposed to remove $6.1 million from test year expenses related to advertising costs. (Dittmer Direct at 91). Specifically, APS purports to remove costs for sports team sponsorships and media advertising to promote the Company's brand identity. *Id.* Staff believes that this adjustment is appropriate because these kinds of expenses are not necessary in order to provide utility service. *Id.*

Staff has identified additional advertising expenses that should also be removed from APS' cost of service. *Id.* at 92. These additional expenses include APS' Dodge Theatre sponsorship costs, sports suite costs, and various other Pinnacle West advertising costs that have been allocated to APS. Like the advertising expenses that APS removed from the test year, these additional items are not related to providing utility service. *Id.* APS has accepted this adjustment. *Id.*

In surrebuttal testimony, Staff witness Dittmer addressed additional advertising adjustments that were proposed by RUCO and were incremental to Staff's original advertising adjustment. (Dittmer Surrebuttal at 24-25). Staff recommends that the Commission adopt these additional APS – conceded advertising adjustments in its final order.

I. Non-Recurring Out-Of-Period Shared Services Expenses

Staff removed from the test year two out-of-period accruals recorded as PWEC administrative and general expense. (Dittmer Direct at 93). Because APS agrees that this adjustment is appropriate, Staff's testimony on this issue is not extensive. *Id.* Accordingly, the Commission should adopt this significant adjustment, which has been conceded by APS.

J. Legal Costs Incurred in Selling the PWEC Silverhawk Power Plant

Staff removed from the test year the cost of legal expenses incurred by Pinnacle West Energy Corporation ("PWEC") related to the sale of the Silverhawk Power Plant. (Dittmer Direct at 93). Although the sale of the Silverhawk plant did not occur until after the end of the test year, many costs related to that sale were incurred during the test year and were charged to PWEC operation and maintenance expense. *Id.* The appropriate level of PWEC operation and maintenance expense is relevant to this case because the Commission authorized APS to rate base a number of the PWEC units in APS' last rate case. *Id.* The Silverhawk Plant, which is located in Nevada, is not one of the PWEC facilities acquired by APS in connection with the last rate case. *Id.* at 93-94. Staff believes that all costs related to the Silverhawk Plant should be removed from APS' cost of service in this case.

APS agrees with this concept. When developing its PWEC O&M adjustment, the Company estimated the costs that were incurred by the various shared services departments that were related to owning and operating Silverhawk during the test year. *Id.* at 94. APS then eliminated a number of these costs from PWEC's test year operation and maintenance expense. *Id.* APS' adjustment, however, fails to capture all test year costs attributable to Silverhawk. *Id.* Staff's adjustment C-10 is intended to capture and remove these additional costs. *Id.*

Staff adjustment C-10 relates specifically to legal fees. *Id.* at 93-94. In the test year, the shared services Law Department incurred $1,394,011 of costs related to PWEC. *Id.* at 94. When developing its PWEC O&M adjustment, APS estimated that ten percent of these costs ($139,401) were related to Silverhawk. *Id.* APS therefore removed $139,401 of the Law Department's costs from PWEC's test year O&M expense. *Id.* at 94-95. APS' adjustment, however, fails to include all legal fees related to the sale of Silverhawk. In discovery, APS identified additional charges totaling $289,400 that were specifically related to the Silverhawk sale. *Id.* at 95. Accordingly, Staff eliminated the costs related to the Silverhawk sale that exceed APS' original adjustment, i.e., \$139,401. *Id.* APS agrees with Staff's adjustment.

K. Non-Recurring Tax Research Costs

Staff's adjustment to schedule C-12 eliminates total non-recurring expenses of \$2,778,128 related to investment tax credit ("ITC") research. (Dittmer Direct at 103). There are two components of this adjustment, both of which are related to charges for non-recurring tax research that were recorded in the test year. *Id.* at 100. Staff's adjustment to schedule B-3 reflects a rate base offset for ITCs. (Dittmer Direct at 106; Dittmer Surrebuttal at 43-45).

1. Reversal of non-recurring credit to joint facility owners that was recorded during the test year as additional production expense.

APS retained Deloitte and Touche, LLP ("Deloitte"), an independent certified public accounting firm, to research whether prior federal income tax returns could be amended in order to claim additional investment tax credits ("ITCs") related to plant that had been constructed in the mid to late 1980s. (Dittmer Direct at 100). Although the Tax Reform Act of 1986 generally eliminated ITCs, there exists the ability to claim some amount of ITCs related to plant that was under construction, but not in service, as of the end of 1986. *Id.* at 100-01. In APS' case, the Palo Verde units were still under construction at that time. *Id.* at 101.

APS retained Deloitte on a contingency basis whereby Deloitte would only be paid out of actual realized "tax savings" related to the additional ITCs. *Id.* In 2003, APS accrued \$2,385,468 in anticipation of paying Deloitte as a result of expected ITCs to be claimed as a result of Deloitte's tax research. *Id.* This accrual occurred after the last APS rate case test year and well before the beginning of the current rate case test year. *Id.*

APS is a joint owner of several generating facilities. *Id.* Pursuant to operating agreements with the joint owners, APS is permitted to "load" direct production costs incurred at the jointly owned plants with administrative and general ("A&G") costs incurred by APS. *Id.* at 101-02. In

2003, a portion of the A&G costs loaded onto the direct-assigned production costs included the accrual for the contingency fee expected to be paid to Deloitte for tax research related to ITCs. *Id.* at 102. The joint owners eventually contested the "loading" of A&G costs that included the Deloitte contingency fee, and APS ultimately conceded that it would be inequitable to charge the joint owners for tax research from which they would not benefit. *Id.* APS subsequently "credited" the joint owners for overbillings made in 2003 related to the Deloitte tax research. *Id.* This "credit" resulted in the recording of incremental APS production expense during the test year in the amount of $1,224,795. *Id.* Thus, one part of Staff adjustment C-12 reverses the non-recurring credit to joint owners that was recorded during the test year as additional APS production expense.

2. Reversal of non-recurring tax research costs recorded during the test year.

Although Deloitte originally undertook the tax research on a contingency basis, these compensation arrangements were eventually changed to a fee-for-service basis. (Dittmer Direct at 102). As a result, APS recorded $1,533,333 during the test year for outside services expense for the tax research undertaken by Deloitte. *Id.* at 102-03. Staff therefore eliminated these non-recurring tax research costs from the test year. *Id.* at 103. APS has conceded that both portions of Staff's adjustment related to tax research are appropriate.

3. Investment Tax Credits as a Rate Base Offset

As a result of the ITC tax research, a tax refund in the amount of $6,483,389 is expected and "imminent." (Dittmer Direct at 103). Thus, for a total outlay of $3,918,801 in cash (composed of the contingency fee of $2,385,468 and a fee-for-service charge of $1,533,333), APS is expected to receive $6,483,389 in tax savings. *Id.* Stated in revenue requirement terms, APS is receiving approximately $10 million of before-tax savings in exchange for incurring $3,918,801 of tax research expense, thereby resulting in a before-tax gain of approximately $6.1 million. *Id.*

In his direct testimony, Staff witness Dittmer recommended sharing the $6.1 million of revenue requirement savings on a fifty/fifty basis between ratepayers and shareholders. *Id.* at 103-06. In rebuttal, however, APS argued that the majority of Staff's proposed rate base adjustment for ITCs will violate Internal Revenue Code ("IRC") "normalization" requirements. (Dittmer Surrebuttal at 42).

In response, Staff has modified its proposed adjustment so that a normalization violation will not occur. *Id.* at 42-43, 45. APS claims that 62% of Staff's originally proposed rate base adjustment will result in a normalization violation. *Id.* at 43. Staff therefore reduced its original rate base adjustment to eliminate 62% of the ITCs related to property that has already been fully depreciated for tax purposes. *Id.*

Of the remaining 38% of ITCs, APS further claims that only the unamortized balance may be allowed as a rate base offset in order to comply with IRC normalization requirements. *Id.* In surrebuttal, Staff has proposed that the Commission recognize as a rate base offset all of the unamortized ITC balance related to plant not fully depreciated. *Id.* For purposes of calculating this adjustment, Staff assumed that one-half of the ITCs would be amortized as of the end of the test year. *Id.* This adjustment is reasonable because it is equitable to credit ratepayers with at least some of the savings realized by APS when it amended its prior years' tax returns. *Id.* Because the majority of ITC savings cannot be shared with ratepayers, it is only fair that savings from "unrestricted" ITCs be credited to ratepayers in this proceeding. *Id.* at 43-44. Specifically, Staff's calculation of this adjustment will allow APS to retain all of the ITC savings that result from the 62% of ITCs that are fully amortized and one-half of the remaining 38% of ITC savings realized. *Id.* at 44. This treatment provides some benefits to ratepayers without causing any normalization violations. *Id.*

APS witness Froggett agrees that Staff's revised ITC rate base adjustment will not result in a normalization violation. However, after Staff had addressed Mr. Froggett's only rebuttal argument—the IRC normalization issue—Mr. Froggett argued for the first time in rejoinder that Staff's revised adjustment is not equitable. For the reasons stated above, Staff's revised ITC rate base adjustment is not only reasonable for APS' ratepayers but also quite generous for APS' shareholders. (Tr. at 4215).

L. Incentive Compensation

Staff adjustment C-13 represents a partial disallowance of test year incentive compensation expense. (Dittmer Direct at 106). Staff recommends eliminating costs associated with APS' *stock-based* incentive compensation plans and allowing recovery of test year expenses associated with APS' *cash-based* incentive compensation plans. *Id.* Staff's adjustment still allows approximately $17.8 million of cash incentive compensation expense (before jurisdictional allocation) and disallows only $4.8 million of stock-based incentive compensation expense. *Id.* at 107, 110.

Staff recommends disallowing APS' stock-based incentive compensation expenses because the award of these incentives is entirely driven by Pinnacle West earnings objectives that, at best, *might* indirectly provide benefits to ratepayers. *Id.* at 110-11. It is undeniable that APS' stock-based incentive compensation plan is aligned with stockholder—and not ratepayer—interests. Specifically, the stated purpose of APS' stock-based incentive plan is "to promote the success and enhance the value of Pinnacle West Capital Corporation . . . by linking . . . [the employees' personal interests] to those of . . . [the] shareholders . . . ." (APS Response to Staff Data Request No. UTI-1-83, Attachment APS09850 (quoted in Dittmer Direct at 107-08)). APS' stock-based incentive compensation programs are driven by the financial performance of Pinnacle West, rather than the operational performance of APS as a public utility. *Id.* at 108. Although corporate earnings also serve as a precondition to the payout of APS' cash-based incentive compensation, the Company-proposed level of test year cash-based incentive compensation is tied primarily to performance measures that benefit APS' customers. *Id.* at 108-10. By contrast, the stock-based incentives are entirely driven by Pinnacle West earnings objectives. *Id.* at 111.

Enhanced earnings levels can sometimes be achieved by short-term management decisions that may not encourage the development of safe and reliable utility service at the lowest long-term cost. *Id.* For example, some maintenance can be temporarily deferred, thereby boosting earnings. *Id.* at 112. But delaying maintenance can lead to safety concerns or higher subsequent "catch-up" costs. *Id.* Rate recovery of stock-based incentive compensation that is exclusively tied to shareholders' interests is simply bad regulatory policy. *Id.* The Commission should therefore disallow APS' stock-based incentive compensation expenses from the Company's cost of service.

M. Lobbying Expenses

The Staff adjustment reflected in Schedule C-15 eliminates test year above-the-line charges for lobbying expense. (Dittmer Direct at 113). Lobbying expenses are not generally included within the development of utility cost of service. *Id.* at 113-14. Pursuant to the FERC Uniform System of Accounts, lobbying costs are required to be recorded below the line, where there is a presumption of non-recovery. *Id.* at 114-15.

Ratepayers could potentially be harmed by allowing cost recovery of lobbying expenses. *Id.* at 115. With the unique monopoly status that utilities enjoy, the potential for abuse through the promotion of unfair or unnecessary legislation is obvious. *Id.* Staff does not mean to suggest that all utility lobbying efforts are detrimental to ratepayers in particular or the public in general, and it is possible that, in certain instances, utility-supported legislation has benefited ratepayers. *Id.* at 116. However, it is virtually impossible to know at what cost the achievement of even pro-consumer legislation is accomplished. *Id.*

What is perceived as "good lobbying" from the utility's or ratepayers' point of view may be considered "bad lobbying" from another constituent's point of view. For instance, as Staff witness Dittmer discussed, a utility may lobby against—and succeed in defeating—certain expensive environmental legislation. Although ratepayers may receive an economic benefit from such lobbying, residents in general may suffer adverse health consequences from the defeat of such legislation. (Tr. at 4269-70). Staff believes that the Commission should refrain from involving itself in the process of discerning "good lobbying" from "bad lobbying."

During the test year, APS recorded some of its lobbying costs below the line, and those costs were not included in APS' proposed test year cost of service. (Dittmer Direct at 116). However, contrary to specific USOA guidelines, APS charged a number of its lobbying costs above the line to administrative and general expense accounts, and these lobbying costs were included in its proposed test year cost of service. *Id.* It is these above the line lobbying expenses that Staff has eliminated on Schedule C-15. *Id.*

In addition to adopting this disallowance, the Commission should require APS to record all lobbying expenses below the line in FERC USOA Account No. 426.4. *Id.* Although the requirement to record lobbying expenses below the line is not conclusive for ratemaking purposes, it will ensure that the issue is highlighted for review by auditors. *Id.* at 116-17. APS will be free to request cost-of-service recognition for lobbying efforts in subsequent rate cases. *Id.* at 117. However, if these costs are appropriately recorded below the line, APS will be required to propose a specific adjustment to its operating income in order to recover these costs in rates. *Id.* This will ensure that expenses that are presumed to fall outside of the Company's cost of service are not "hidden" within inappropriate accounts, thereby complicating the audit. *Id.*

N. ISFSI Expense

The Independent Spent Fuel Storage Installation ("ISFSI") is Palo Verde's dry storage facility for spent nuclear fuel. (Dittmer Direct at 117). The storage pools where Palo Verde's spent fuel is currently stored will soon reach maximum capacity, and Palo Verde will therefore need an interim storage facility until the United States Department of Energy can site and construct permanent storage facilities for spent nuclear fuel. *Id.* at 117-18.

The need for this interim storage facility has been anticipated for a number of years. *Id.* at 118. In a previous decision, the Commission allowed APS to defer ISFSI costs within a regulatory asset account for later recovery from ratepayers. *Id.* In Decision No. 67744, issued in 2005, the Commission allowed APS to recover these previously deferred ISFSI costs. *Id.* That decision also allowed APS to recover ongoing ISFSI costs related to current nuclear fuel burns. *Id.* Both of these issues—the recovery of previously deferred ISFSI costs and the recovery of ongoing ISFSI expense—were examined in a study undertaken by TLG Services, Inc. in 2002. *Id.* In the pending case, APS is again proposing ISFSI adjustments. *Id.*

Decision No. 67744 (APS' last rate case) did not become effective until April 1, 2005. (Dittmer Direct at 118). The test year in this case, which ends September 30, 2005, reflects only one-half of the annual amortization level of deferred ISFSI costs that were approved in Decision No. 67744. *Id.* Therefore, APS has proposed an adjustment to reflect the annualization of the amortization expense related to the ISFSI deferrals approved for recovery in Decision No. 67744. *Id.* Staff has accepted this adjustment.

APS also proposes adjustments that reflect incremental "ongoing" ISFSI expense as well as incremental ISFSI amortization expense resulting from the TLG Services, Inc. study that was updated in 2004. *Id.* Finally, APS proposes an adjustment to ISFSI amortization expense to consider additional deferrals following June 30, 2004, the cutoff date used in the last rate case, through December 31, 2006, the approximate effective date for rates developed in this proceeding. *Id.* at 118-19.

Staff accepts the majority of APS' proposed ISFSI adjustments, but nonetheless proposes certain minor modifications in its adjustment set forth in Schedule C-16. *Id.* at 121-25. The updated 2004 TLG study predicts an overall increase in ISFSI costs from that projected in the 2002 study. *Id.* at 124. Furthermore, the 2004 study predicts a significant shift in ISFSI expenditures from post-shut down activities that have a long amortization period to pre-shut down activities that have only a five-year amortization period. *Id.* APS' ISFSI adjustments incorporate both the higher overall ISFSI estimate and the shift of costs to pre-shut down activities that have a shorter amortization period. *Id.* However, the 2004 TLG study also predicts a reduction in costs related to post-shut down activities, and APS' ISFSI adjustments fail to capture those reductions. *Id.* at 125. Conceptually, Staff's ISFSI adjustment captures the reduction in costs for post-shut down activities that were ignored by APS. Staff believes that it would be unfair to reflect in rates the elements of the 2004 TLG study that show increased costs but to omit the elements of the same study that show declining costs. *Id.*

O. Property Tax Expense

Staff has proposed an adjustment to APS' proposed level of property tax expense. (Dittmer Direct at 125). In his direct testimony, Staff witness Dittmer recommended eliminating the portion of APS' pro forma property tax adjustment related to a property tax increase anticipated to occur in 2007. *Id.* APS had designed one element of its proposed property tax adjustment to reflect the statutory phase-in of property tax increases associated with the former PWEC units. *Id.* Although it is probable that property taxes related to these facilities will increase, "cherry picking" post test year changes that occur far beyond the end of the test year will result in a mismatch in cost of service revenues, expenses, and rate base. For these reasons, Staff eliminated the portion of APS' property tax adjustment that is related to anticipated 2007 tax increases. *Id.* at 125-26. APS has agreed to Staff's property tax adjustment.

At the hearing, Staff witness Dittmer stated that he supports RUCO's additional property tax adjustment. (Tr. at 4187-89). Specifically, RUCO identified a known and measurable reduction in property tax expense that became effective in 2006 as a result of new legislation. In rebuttal, APS claims that, notwithstanding the reduction in 2006 property tax expense, its 2007 property tax expense will still be higher than either its test year actual property tax expense or its 2006 adjusted property tax expense. Staff, however, agrees with RUCO on this issue: to adopt 2007 property tax levels would create a mismatch in the development of APS' cost of service.

Furthermore, APS' position on this issue is inconsistent with its revised production tax credit proposal. During discovery, APS suggested that it should not reach into 2007 to incorporate a higher production tax credit rate than would be available to it in 2006. Staff witness Dittmer agreed with APS and reduced APS' originally proposed cost of service income tax expense to reflect the lower

2006 production tax credit rate. It would therefore be both unfair and inconsistent to adopt higher projected 2007 property tax expense and ignore the reduction in the production tax credit that will become available to APS in 2007. (Tr. at 4190-92). For these reasons, the Commission should adopt both Staff's and RUCO's property tax adjustments.

P. Generation Production Income Tax Deduction

APS has proposed an income tax adjustment to reflect additional tax deductions and accompanying tax savings that will result from the American Jobs Creation Act. (Dittmer Direct at 126). Staff agrees with APS' approach, but nonetheless proposes some adjustments.

When APS prepared its original case, the treasury regulations related to the American Jobs Creation Act were not final. *Id.* at 127-28. APS therefore relied upon *proposed* treasury regulations, which were subsequently superseded by the final regulations. Staff's adjustment on this issue merely calculates the additional tax deductions and accompanying tax savings based upon those final regulations. *Id.* at 126-27. APS has accepted this adjustment. *Id.* at 127. Staff has also proposed adjustments intended to synchronize this adjustment with other elements of Staff's position in this case. *Id.* at 127-28.

Additionally, Staff recalculated the production tax credit to reflect the three percent credit that was available in 2006 rather than the six percent credit available in 2007, which APS used to calculate its original proposal on this issue. Staff believes that it will create a mismatch to selectively adopt cost of service elements scheduled to occur in 2007 and beyond. (Tr. at 4190-92).

Q. Interest Synchronization

Staff has adjusted APS' pro forma level of income tax expense to synchronize the interest deduction for consideration in the development of Staff's cost of service income tax expense with the jurisdictional rate base and weighted cost of debt proposed by Staff. (Dittmer Direct at 129). This adjustment, which is routinely adopted by regulatory commissions in utility rate cases, is derived by multiplying Staff's proposed retail jurisdictional rate base times the weighted cost of debt included within Staff's development of the overall cost of capital. If the Commission were to adopt a different rate base or weighted cost of debt than that proposed by Staff, it would be necessary to revise this adjustment accordingly. *Id.*

R. Federal And State Income Tax Expense

Staff proposes an adjustment as a correcting calculation to APS' proposed level of cost of service income tax expense. (Dittmer Direct at 129). Although most accountants can agree conceptually to the appropriate development of allowable cost-of-service income tax expense, the mathematical or mechanical computation of such an adjustment can become complicated. *Id.* at 129-30. This is especially true in this case, which addresses an historic test year that spans two calendar years, each of which may include unique or non-recurring tax accrual entries. *Id.* at 130.

As a result of a series of discussions with APS personnel, Staff witness Dittmer concluded that an error exists within the Company's development of its proposed test year cost of service income tax expense, even though the precise error was never precisely identified. *Id.* Staff proposed a "top down" calculation that uses estimated 2006 permanent book/tax differences and other income tax credits. *Id.* at 130-31. APS has accepted this adjustment. *Id.* at 131.

S. RUCO's Palo Verde Steam Generator Replacement Depreciation Issues

APS proposed a post test year adjustment to reflect a steam generator replacement at Palo Verde. No party has objected to this adjustment. RUCO, however, has proposed two corresponding adjustments, which Staff supports.

First, RUCO has proposed an adjustment to reflect a corresponding retirement related to the post-test year Palo Verde steam generator replacement. APS' failure to reflect the associated retirement overstates APS' proposed balance of gross plant in service. Second, RUCO proposed an adjustment to depreciation expense to reflect the impact of the retirement associated with the Palo Verde steam generator replacement. Because APS had annualized depreciation expense based upon the overstated balance of gross plant in service, APS' proposed pro forma level of depreciation expense was also overstated. APS agreed with these RUCO adjustments, and the Commission should adopt them.

T. RUCO's Customer Deposit Interest Annualization Adjustment

RUCO proposed an adjustment to reflect the interest rate that was paid on customer deposits in 2006, and APS agreed with this adjustment in rebuttal. Staff has reflected this adjustment within its updated accounting schedules filed with Staff's surrebuttal testimony. (Ex. S-38; Schedule B, p.1). This adjustment should also be adopted in the Commission's decision in this matter.

VIII. POWER SUPPLY ADJUSTER

Staff believes that it is appropriate for the Commission to continue to approve some type of Power Supply Adjuster ("PSA") mechanism for APS, because prices for fuel and energy remain volatile. (Antonuk Direct at 4). That volatility will likely continue for some time, and will substantially diminish the chance that rate case determinations for fuel and energy expenses will bear a reasonably close relationship to actual costs for those items during the period that rates are in effect. *Id.*

Staff has proposed several changes to APS' existing PSA:

1) The use of a forecasted year for setting the PSA rate in the future;

2) The elimination of the 90/10 sharing mechanism;

3) The elimination of the $776 million cap;

4) The elimination of the 4 mil bandwidth;

5) The adoption of a new plan of administration, which would replace the existing plan of administration.

(Antonuk Direct at 33, 37; *see generally* Antonuk Supplemental Test., hereinafter referred to as "Antonuk Supplemental", Ex. S-30 at 2-8).

For a number of reasons, the existing PSA mechanism led to the build-up of substantial undercollections in 2005-06. (*See* Dittmer Surrebuttal at 6; Tr. at 3033). The combination of implementing a new PSA in conjunction with the increase in fuel and purchased power prices in the wake of Hurricane Katrina led to significant and unanticipated undercollections in APS' fuel and purchased power costs. This build-up of deferrals attracted unfavorable attention from the ratings agencies, which threatened to downgrade APS' ratings. (*See* Parcell Direct Test., Ex. S-8 at 14). Arguably, this build-up of deferrals also prompted APS to file its emergency rate case in early 2006. (Tr. at 3033).

In evaluating APS' rate case, Staff recognized that the public interest would be served by addressing any aspects of APS' existing PSA that may have contributed to the build-up of significant deferrals. Staff believes that the changes that it is recommending will lead to more timely recovery by APS of its costs for fuel and purchased power. Staff also believes that these changes will address the rating agencies' concerns, as alleged by APS.

Staff's proposed Plan of Administration provides a detailed description of the mechanics of Staff's proposed PSA. (Antonuk Supplemental, Ex. S-30). The "forward component" of Staff's proposed PSA has some bearing on the issues related to the base cost of fuel and purchased power. Although Staff recommends that the Commission reject APS' 2007 forecasts as the basis for the base cost of fuel and purchased power, Staff does not object to using APS' 2007 rejoinder forecast to determine the "forward component" for 2007. Adoption of this proposal would essentially serve as a "middle ground" between the competing positions of Staff and APS regarding the appropriate base cost of fuel and purchased power. (Antonuk Supplemental at 2-3, 5-6).

IX. COST OF CAPITAL

The first step in performing a cost of capital analysis is the development of an appropriate capital structure. The second step is a determination of the embedded cost rate of long-term debt. The third step is the estimation of the cost of common equity. Although the first two steps are not generally controversial, the third step often generates significant dispute.

For the cost of equity evaluation, Staff applied three recognized methodologies (discounted case flow, capital asset pricing model, and comparable earnings) to two proxy groups (a group of comparison electric utilities with similar operating and risk characteristics to APS and PWC, and the group of proxy electric companies analyzed by Company witness Avera). Based upon these analyses, Staff has concluded that the cost of common equity for APS falls within a range of 9.5 percent to 10.75 percent, with an approximate midpoint of 10.25 percent. Combining the three steps of the cost of capital analysis into a weighted cost of capital results in an overall rate of return of 8.05 percent. (*See generally* Parcell Direct; Parcell Surrebuttal Test., Ex. S-9).

A. Economic Principles

Cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated. There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the capital structure item that is the most difficult to determine. These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), comparable earnings, ("CE"), and risk premium ("RP") methods. Each of these methods is different, and if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

Economic and financial conditions are also important in determining the cost of capital. The level of economic activity, the stage of the business cycle, the level of inflation, and expected economic conditions all have a direct and significant influence on the cost of capital. Currently, capital costs are low in comparison to the levels that have prevailed over the past three decades. Even a moderate increase in interest rates, as well as other capital costs, would still result in capital costs that are low by historic standards. Therefore, it can reasonably be expected that cost of equity models, such as the DCF, will currently produce returns that are lower than was the case in prior years.

B. Capital Structure

A utility's capital structure is important since the concept of rate base/rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. The purpose of determining the proper capital structure for a utility is to help ascertain the capital costs of the company. APS has proposed the following capital structure: long term debt- 45.5 percent, and common equity - 55.5 percent. This capital structure contains a higher equity ratio than that of the electric utilities in both the general and the specific proxy groups. Therefore, the APS capital structure reflects a lower degree of financial risk than that exhibited by the proxy groups. Staff has nonetheless accepted APS' proposed capital structure for purposes of determining APS' cost of capital in this proceeding.

C. Cost of Long-Term Debt

The Company's filing proposes a long-term debt cost of 5.41 percent, and Staff has determined that this proposal is reasonable.

D. Cost of Equity

The common equity ratio is the capital structure item that receives the most attention. This is because common equity usually commands the highest cost rate, generates associated income tax liabilities, and causes the most controversy since its cost cannot be precisely determined. It is not possible to conduct direct analyses of the cost of common equity for APS because it is not a publicly traded company. It is possible to conduct studies of PWC's cost of equity, but due to the diversified nature of PWC's operations, it is not an adequate proxy for the cost of equity for APS. As a result, it is useful to analyze groups of comparison or "proxy" companies as a substitute for APS to determine its cost of common equity. Two groups were examined for comparison to APS: 1) a selected group of electric utilities similar to APS and PWC, and 2) the proxy group of electric utilities selected by APS witness Avera.

1. Discounted Cash Flow Analysis

The discounted cash flow (DCF) model is one of the oldest as well as the most commonly used models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. The relationship can be simplified because dividends are assumed to grow at a constant rate of g. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. The constant growth equation can be solved for the cost of capital. When doing so, the return expected or required by investors is comprised of two factors: the yield (current income) and expected growth (future income).

There are several methods which can be used for calculating the yield component. These methods generally differ in the manner in which the dividend rate is employed, such as current versus future dividends or annual versus quarterly compounding of dividends. However, the most appropriate yield component is a quarterly compounding variant that recognizes the timing of dividend payment and dividend increases. The growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the growth component is to reflect the growth expected by investors which is embodied in the price of a company's stock. Also, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. A wide array of techniques exists for estimating the growth expectations of investors. No single indicator of growth is always used by all investors, and it is necessary to consider alternative indicators of growth in deriving the growth component of the DCF model.

Staff considered five indicators in its DCF analyses: (1) 2001-2005 earnings retention, or fundamental growth; (2) 5-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS); (3) 2006-2010 projections of earnings retention growth; (4) 2004-2010 projections of EPS, DPS, and BVPS; and (5) 5-year projections of EPS growth as reported in First Call. This combination of growth indicators is a representative and appropriate set with which to estimate investor expectations of growth for the groups of utility companies. Based on Staff's analyses, a range of 9 percent to 10 percent represents the current DCF cost of equity for APS. The lower end (9 percent) approximates the upper values for the average/median results, while the upper end (10 percent) reflects the high value of the constant growth DCF calculations for the groups examined.

Although APS witness Avera performed a DCF analysis, he concluded that its results were not useful (presumably too low) in estimating a reasonable cost of equity for APS. (Tr. at 1863-65). By contrast, both Staff and RUCO have appropriately incorporated the results of their respective DCF analyses into their recommendations, recognizing that the DCF method is commonly relied on by regulatory commissions – including this Commission – to estimate the cost of equity. *Id.* at 1869-70.

2. *Capital Asset Pricing Model Analysis*

The capital asset pricing model (CAPM) is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory (MPT), which studies the relationships among risk, diversification, and expected returns. The CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry, whereas the simple risk premium method does not. Staff performed CAPM analyses for the same groups of electric utilities evaluated in the DCF analyses.

Two types of Treasury securities are often utilized as the risk free rate component: short-term United States Treasury bills and long-term United States Treasury bonds. The three month average yield for twenty year United States Treasury bonds was used for Staff's CAPM calculations. Staff also used the most current Value Line betas for each company in the groups of comparison electric companies in its CAPM calculation. The market risk premium component represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, returns of the S&P 500 and 20-year United States Treasury bonds were used. A combination of arithmetic and geometric means is appropriate since investors have access to both types of information, and both types are reflected in investment decisions and thus stock prices and cost of capital. Staff's CAPM results collectively indicate a cost of about 10.5-10.75 percent for the two groups of proxy companies.

3. Comparable Earnings Analysis

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, since it translates into practice the competitive principle upon which regulation rests. The CE methodology is conducted by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. One objective of a fair cost of equity is the maintenance of stock prices above book value. Staff considered experienced equity returns of the proxy groups of companies for the historic period 1992-2005 as well as the future period 2006-2010 in its analysis. Historic returns of 9.9-11.7 percent have been adequate, and projected returns on equity for future periods are within a range of 8.2-10.4 percent for the proxy groups. Therefore, the cost of equity for APS is no greater than 10 percent, and an earned return of 10 percent or less should result in a market-to-book ratio of at least 100 percent.

E. Total Cost Of Capital

The overall conclusion from the three methodologies (DCF, CAPM and CE) is a range of 9.5 percent to 10.75 percent, and Staff's specific recommendation for APS' cost of equity is 10.25 percent, the approximate mid-point of that range. In addition, there is no need to make a flotation adjustment. A utility should only be allowed to recover from ratepayers its actual quantifiable levels of issuance costs. Staff's recommended overall weighted cost of capital for APS is 8.05 percent.

X. PALO VERDE ISSUES

A. Palo Verde Nuclear Outages Resulting From Imprudence Are the Responsibility of the Company.

Beginning in 2005, the Palo Verde Nuclear Generating Station ("Palo Verde") experienced unusually low performance. The Nuclear Regulatory Commission ("NRC") ranked the facility at next to the lowest possible level for an operating plant. (GDS August 17, 2006 Report, hereinafter referred to as "GDS Report", Ex. S-45 8). Further, the Institute of Nuclear Power Operations purportedly ranked Palo Verde as an INPO-3 which the Company concedes reflects poorly on the performance of the plant. (Tr. at 5161-62).

Because of the high capital investment costs of a nuclear power facility, efficient plant operation is fundamental to attaining the low operational costs that make nuclear power competitive with other means of generation. In 2005, Palo Verde experienced eight unplanned outages, thereby requiring APS to seek replacement power to meet its commitments. These outages, as well as the low evaluations of Palo Verde, suggested a need to investigate the causes of this poor performance.

The results of that investigation reveal a steady deterioration in Palo Verde's performance, which culminated in low regulatory marks and accounted for four of the unplanned outages in 2005. Initially, Staff determined that these four imprudent outages resulted in a $16.269 million cost for replacement power, of which 14.944 million was incurred in April-December of 2005 when the PSA was in effect. However, in surrebuttal, Staff accepted certain changes proposed by Company witness Ewen. In total, these changes effect a $1.188 million reduction to Staff's estimate. Thus, Staff's final estimate of the cost of replacement power is approximately $15.082 million,[2] with $13.757[3] million occurring during the effective period of the PSA. The investigation also outlined options that the Commission could pursue in the form of a Nuclear Performance Standard. Such a mechanism

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[2] $16.269 million – $1.188 million = approx $15.082 million.
[3] $14.944 million – $1.188 million = approx $13.757 million.

would contribute to effectively distributing the costs of poor performance between the Company and ratepayers. Without such a mechanism, the costs of poor performance fall solely on ratepayers, who cannot influence the efficiency of Palo Verde's operations.

1. The Outages are the result of imprudence on the part of the Company.

During 2005, Palo Verde experienced a total of eleven planned and unplanned outages. Of these outages, Staff identified four as the result of imprudence. (GDS Report at 2). The approximate impact of these outages in terms of the cost of replacement power is $15.082 million, $13.757 million of which occurred during the period in which the PSA was effective. *Id.* at 41-53. In addition to power replacement costs, APS experienced reduced margins on off-system and opportunity sales used to offset fuel and purchased power costs recovered through the PSA. These items should thus also be counted as a component of the total cost of the imprudent outages. Factoring in the lost margins on off-system and opportunity sales results in a total cost of $16.186 million. The ratepayers are not responsible for these outages and should not be forced to bear these costs.

Four discreet instances give rise to the imprudent outages that will be discussed further below. Briefly, they are the Emergency Diesel Generator Governor failure (March 18-21, 2005), the Extended Outage due to an operator-caused Reactor Trip on high steam generator level (August 26-28, 2005), the Unit 2 Refueling Water Tank inoperability (October 11-20, 2005), and the Unit 3 Refueling Water Tank inoperability (October 11-20, 2005).

a. The Emergency Diesel Generator Governor Failure (March 18-21)

Following maintenance, the Company performed a post-maintenance test of one of the Unit 1 Emergency Diesel Generators ("EDG"), a vital safety device necessary to provide power in the event of disconnection from offsite power sources. As Company witness Denton testified, in the event of losing off-site power, EDGs are necessary to ensure the orderly and safe shut down of the plant. (Tr. at 5040). According to NRC regulations, APS is required to shut down the unit if both EDGs are not available to operate for an extensive period of time. *Id.* at 5041. In fact, both EDGs are necessary in the event of an actual loss of off-site power. *Id.* During the retest of the equipment on March 17, 2005, one of the two EDGs failed to start. Operators determined that the cause of the failure was a faulty governor for the EDG. Though the governor was replaced, technical specifications require the shutdown of the unit during the retest.

Examination of the governor failure pointed to rust as the source of failure. Though the Company cited a number of possible causes for the rust, (*see* Tr. at 5136-5137), all of these possible causes indicate that APS' inability to detect and prevent the failure was due to imprudence. The governor was stored in a non-climate controlled warehouse, drained of oil. (GDS Report at 23). Had the Company stored the governor with oil in it, it could have avoided the governor failure and the outage. (*Id.* at 24. *See also* Tr. at 5139-5140). Because each unit requires both EDGs to be operable in the event of a loss of off-site power, and because the loss of an EDG for extended periods requires shutdown of the affected unit, (Tr. at 5041), it is clear that the Company did not treat the EDGs with the degree of care appropriate to the significance of this particular piece of equipment.

b. Unit 1 Reactor Trip and Outage Extension Due to Operator Error (August 26-28, 2005).

Operator error exacerbated an otherwise unavoidable outage that began on August 11, 2005 with the failure of Unit 1's second EDG. A faulty diode in the voltage regulator prevented the EDG from maintaining the proper steady output voltage. A further, unavoidable equipment failure, namely an oil leak on a reactor coolant pump, likewise delayed the restart of Unit 1.

On August 26, 2005, operator error during startup caused an avoidable extension of the outage. Specifically, the steam generator operator failed to obtain supervisory approval before switching to manual operation of the digital feedwater control system ("DFWCS") when he perceived that the automatic settings were not raising the level as high as the operator deemed appropriate. (GDS Report at 24-26). Failure to communicate operator actions led to increased feedwater flow beyond the level necessary for the steaming rate, thereby resulting in a high steam generator level and a consequent reactor trip. *Id.*

The Company did not provide adequate training and permitted a culture of unsupported and inaccurate beliefs among DFWCS operators. The Company conceded that, in the post-event interviews, many operators claimed that the DFWCS was unreliable in maintaining stable feed water levels at low power levels. (Tr. at 5144). Further, the Company conceded that, with respect to the narrow issue of the DFWCS, no updated training or procedures had been set in place to deal with this inaccurate perception. *Id.* at 5144-45.

The Company suggests that the problem was not with the equipment but with the operators who perceived fault with the system. (Levine Rej. Test., Ex. APS-95 at 8). The Company's contention reinforces, rather than detracts from, Staff's conclusions. The operators' erroneous perception of the system was the root of the problem. As Staff testified, reactor startups were unusually frequent during 2005 at Palo Verde, and the Company had many prior experiences with operator misgivings toward the DFWCS. (Jacobs Surrebuttal Test., hereinafter referred to as "Jacobs Surrebuttal", Ex. S-48 at 22-23). The Company understood that a common mindset of anticipated system failure preexisted the event. *Id.* This led to a preemptive and incorrect action by an operator that caused the reactor trip. In spite of its prior knowledge, the Company did not take steps to alter training so as to eliminate this mindset. This failure to address a known problem supports the conclusion that this outage is imprudent.

c. Unit 2 and Unit 3 Refueling Water Tank Inoperability (October 11-20, 2005)

From October 11-20, 2005, Palo Verde Units 2 and 3 were out of operation because the Refueling Water Tanks ("RWT") for both units were declared inoperable. Two safety systems depend on the RWT, the Emergency Core Cooling System ("ECCS") and the Containment Spray.

The declaration of inoperability of these connected systems followed an NRC inspection in 2005. (GDS Report at 32, 39-40; Jacobs Surrebuttal at 24). During the inspection, the NRC voiced the concern that, during suction from the RWT under certain conditions, air could be entrained that could damage and disable the safety pumps on which the Containment Spray and ECCS depend. (GDS Report at 31-32, 39). The Company could not demonstrate to the NRC that air entrainment was not occurring and thus the units were shut down pending a full analysis to determine whether air entrainment threatened safe operations. (Jacobs Surrebuttal at 24).

The Company—instead of the NRC—should have identified this issue because of the NRC's yellow finding in 2004 on a related issue. (*See* Jacobs Surrebuttal at 24-25). The yellow finding in 2004 resulted from empty containment sump piping, thereby raising concerns that air entrainment from the empty sump piping could damage safety related pumps. The Company should have known that air entrainment damage to pumps is a safety concern. Draining the RWT gives rise to the same air entrainment concerns as the empty sump piping. A reasonably complete analysis of the issues related to the 2004 yellow finding would have permitted the Company to identify this largely identical issue. *Id.* Therefore, this outage was avoidable and imprudent.

2. The Proper Measure of the Impact of the Outages requires examining Palo Verde's performance, without considering the unconnected performance of the Company's other operations.

In addition to arguing that the outages were not imprudent, the Company also argues that the improved performance of its coal generation should offset the loss of generation at Palo Verde. This argument is not persuasive and should not be adopted. Improved performance in the Company's coal generation is external and unrelated to the Palo Verde outages. The Palo Verde outages did not cause improved operations at the Company's various coal-fired plants, nor did they produce lower coal prices.

The Company incurred costs for replacement power in spite of the improved efficiency of its coal facilities. These replacement power costs are unaffected by the superior performance of the coal plants even when evaluating them cumulatively. Allowing the performance of the coal facilities to mitigate the costs of the Palo Verde outages would clearly double count the influence of coal generation. The Company's arguments for this type of mitigation should not be accepted.

3. A Nuclear Performance Standard is Appropriate and Reasonable.

The Commission should adopt a performance standard to govern the operation of Palo Verde. As noted above, the Company will recover its cost of invested capital regardless of the quality of its performance, and the ratepayers therefore bear the risk of poor performance. This is unfair when one considers that nuclear plants have exceptionally high capital cost and that only the low cost of fuel and operations offsets the high capital costs. The lower cost of operations can only be achieved when the plant operates at a high capacity factor. Adopting a reasonable Nuclear Performance Standard ("NPS") will alleviate this situation by distributing the cost of inefficient operations on both the Company and the ratepayers. (*See* Tr. at 5128, 5225).

Staff's proposed NPS has the following features:

1) Evaluating Palo Verde performance by averaging capacity factor achieved every three years;

2) Setting the target capacity factor as three year average capacity factor of U.S. nuclear plants similar in type to Palo Verde (pressurized water reactors ("PWR") with over 600 MW capacity);

3) Excluding U.S. PWRs with a three year average capacity factor below 60% from the target capacity factor calculation;

4) Allowing no action if Palo Verde exceeds the target value for the relevant period;

5) Assigning to the Company the cost of replacement power for the difference between actual system costs and system costs had Palo Verde achieved its target capacity factor;

6) Allowing the Commission to determine the treatment of the additional costs; and

7) At Commission discretion, performing detailed studies of extended outages or other extraordinary events that would significantly impact Palo Verde's capacity factor during the three year period.

(Jacobs Direct Test., hereinafter referred to as "Jacobs Direct", Ex. S-47 at 7-8).

a. Regulating Company Operations is a Reasonable Means to encourage APS to Achieve an Appropriate Level of Performance.

APS' Performance Improvement Plan states that APS intends to make Palo Verde a top performing nuclear facility. (*See* GDS Report at 51; *see also* Tr. at 5127). Staff's proposed NPS, which sets the industry average as its target, is not inconsistent with that goal. Likewise, an NPS would reduce the need to undergo extensive and costly investigations of each outage because the averaging mechanism would focus attention properly on the bottom line.

The Company contends that implementation of the NPS, which does not contain incentives, will not affect the way it does business. (Tr. at 5126). Instead of providing an incentive, the NPS reallocates costs associated with poor performance between the Company and ratepayers. Staff's recommendation shifts the impact of operational deficiencies that are solely within the Company's control and thereby applies appropriate pressure to the Company to improve its performance without jeopardizing the recovery of the cost of investment. Thus, regardless of whether the Company pursues operational excellence to avoid the graduated penalties of the NPS, ratepayers will no longer be subsidizing inefficiency.

b. The Performance Standard should solely Consider Palo Verde.

The Company has tentatively expressed willingness to agree to an NPS that examines Company performance overall rather than examining the isolated performance of its single most capital intensive asset, Palo Verde. Evaluating the Company's performance as a whole would produce skewed results. Though nuclear and coal power plants are both used for base load generation, they are fundamentally different. (Jacobs Surrebuttal at 36). They use different operational and safety processes, are subject to different forms of regulation, and have costs that are unrelated and not directly comparable. *Id.* In addition, nuclear facilities are more expensive and should operate with lower variable costs. *Id.* A broad performance standard that includes all of the

Company's generation would, in effect, permit the Company to gloss over the performance of its single most costly asset, Palo Verde.

B. Establishing A Power Supply Adjustor Surcharge To Recover Costs Associated With Nuclear Plant Outages That Have Not Been Identified As Imprudent Or Preventable.

Decision No. 67744 allows APS to recover or refund the amount of increased costs for fuel and purchased power up to a certain limit based on the annual adjustor rate. The Paragraph 19(d) Balancing Account includes only those power supply costs falling outside of the $0.004 bandwidth. The Commission must approve any surcharges to recover or refund any amounts in the Paragraph 19(d) Balancing Account.

Staff's testimony addresses whether the Commission should allow APS to recover through surcharges the costs in its Paragraph 19(d) Balancing Account related to outages at Palo Verde. Staff's Palo Verde report identifies certain outages as impudent, and the costs relating to these outages should therefore be removed from the Paragraph 19(d) Balancing Account. Staff also recommends that the Commission allow APS to recover through a surcharge the costs resulting from the Palo Verde outages that were not imprudent.

XI. PROCUREMENT AUDIT

APS' testimony appears to be in general agreement with the findings of the fuel and purchased power audit conducted by the Liberty Consulting Group on behalf of Commission Staff. (Antonuk Surrebuttal at 1). Staff did not observe any significant matter of disagreement that would affect either the establishment of base rates or the design of the PSA. (Antonuk Surrebuttal at 1). APS has claimed that a number of changes recommended by the audit have already been undertaken; nonetheless, there does not appear to be a difference of opinion about what both APS and Staff have concluded ought to be implemented in order to optimize fuel and energy procurement and management. *Id.*

In these circumstances, a reasonable way to address audit findings is for the Company to prepare 1) an implementation plan for each recommendation that it accepts and 2) a detailed explanation of its reasons for concluding that particular recommendations need not be implemented. *Id.* Staff can then identify the best method for monitoring the Company's implementation plan and for resolving any issues that may be in dispute. *Id.* Staff therefore recommends that the Commission require the Company to prepare an implementation plan as outlined above. *Id.*

XII. ENVIRONMENTAL IMPROVEMENT CHARGE

Staff's testimony addressed APS' proposed Environmental Improvement Charge ("EIC"). APS wants to implement this additional charge to recover its capital investment in coal plant environmental controls. Through the EIC, APS intends to collect revenues from ratepayers based on the estimated capital investment needed to install pollution controls on its coal-fired power plants. Staff recommends that the Commission reject the proposed EIC.

Staff listed the following reasons for rejecting APS' proposed EIC:

1) The EIC would include costs that will not be incurred for several years beyond the test year;

2) The EIC would include funding for projects before they are mandated to be installed on APS' system;

3) Regulatory mandates typically build in construction lead times to provide industry sufficient time to comply with mandated regulatory requirements;

4) The EIC is derived based upon multiple year revenue requirements that increase the complexity of auditing the charge in the context of future general rate cases and annual EIC reset proceedings;

5) The effect of the EIC on APS' interest expense in unclear;

6) The annual reset of the EIC could be implemented without Commission approval under APS' proposal;

7) The EIC does not address the fundamental financial challenges that APS has identified *i.e.*, customer growth and rising fuel costs;

8) The environmental impact of implementing the EIC is unclear.

(Rowell Direct Test., Ex. S-19 at 14-15). Staff highlighted two points in recommending that the Commission reject the proposed EIC: 1) the EIC would collect revenues from ratepayers based predominately upon estimated rather than incurred costs; and 2) the EIC appears to be unique in that Staff is not aware of any jurisdiction that employs a mechanism with the same characteristics as the EIC.

Staff does not support collecting funds from ratepayers, including interest, before the costs have been incurred. This policy is reasonable as applied to APS' proposed EIC in this case. APS has the option of collecting up-front funds for environmental controls from investors, but the EIC would collect these funds from ratepayers. Collecting funds before costs have been incurred means that APS will have to estimate capital expenditures. It is very difficult to accurately compute capital expenditures because costs are unpredictable, and projected completion dates are often unreliable. Customers would be caught in the middle of pre-funding projects that potentially have different costs and later completion dates than expected.

APS' proposed EIC financing scheme is actually contrary to industry standards. This is illustrated by two industry studies: a Cambridge Energy Research Associates' study and a NARUC study. NARUC's study focused on state level incentives for environmental controls on coal-fired power plants. None of the fifteen states that responded to the NARUC study have a cost recovery mechanism similar to APS' proposed EIC. None of the twenty-two states that responded to the Cambridge survey allow companies to collect funds before the costs are actually incurred. Staff was unable to identify any other jurisdiction that employs a mechanism with the characteristics of the proposed EIC.

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XIII. DEMAND-SIDE MANAGEMENT

A. How Should APS Be Compensated For Its Effort To Make DSM Programs Available?

APS proposed a $4,907,000 pro forma adjustment to compensate for net lost revenues resulting from its efforts to create DSM programs. The Settlement Agreement contained in Decision No. 67744 requires APS to intensify its DSM efforts and to spend at least $16 million on DSM per year. In response, APS recently created a number of new DSM programs as part of its Portfolio Plan. Staff opposes APS' pro forma adjustment and recommends that the Commission disallow the net lost revenue adjustments for DSM programs. Staff instead recommends that the Commission reward APS for DSM savings through a performance incentive.

APS should be compensated for its efforts to make DSM programs available and for the savings achieved by successful DSM programs through a performance incentive. A performance incentive and an adjustment for net lost revenues are two separate approaches to compensating the utility. These techniques are mutually exclusive, and the Commission should adopt either approach individually, but not both. (Anderson Direct Test., hereinafter referred to as "Anderson Direct", Ex. S-16 at 9). The Settlement Agreement that underlies Decision No. 67744 provides for a performance incentive, arguably signaling the Commission's preference for that approach.

Conceptually, a performance incentive is preferable to an adjustment for net lost revenues because a performance incentive rewards the Company only when its DSM programs successfully result in energy or demand savings. In other words, APS would not be compensated through a performance incentive if its DSM programs fail to result in energy efficiency savings. The amount collected in performance incentives would represent a portion of the actual energy efficiency savings that APS' DSM programs achieve.

Nor is APS' proposed adjustment for net lost revenues sufficiently known and measurable to merit inclusion in rates. (Anderson Surrebuttal Test., hereinafter referred to as "Anderson

Surrebuttal", Ex. S-17 at 4; Tr. at 3641). Staff believes that DSM spending for the remainder of the Portfolio Plan period, 2005-07, is very much in question. The energy savings resulting from that spending is even more difficult to quantify with certainty. (Anderson Surrebuttal at 4). In addition, Staff believes that, to date, there has not been a significant amount of lost revenue due to DSM programs. Thus far, the Company has incurred up-front costs, but significant energy savings and reduced revenues resulting therefrom have not yet fully materialized. (Tr. at 3648).

APS proposed a performance incentive in its Portfolio Plan of DSM programs, and Staff concurred with that proposal, which sets the performance incentive at 10 percent of the net benefits achieved and caps it at 10 percent of total DSM spending. Staff recommends that APS include its request for a performance incentive in each semi-annual DSM report. Staff also recommends that APS provide Staff with backup workpapers and input data to substantiate the numbers for net benefits and performance incentives included in its semi-annual DSM reports.

Staff recommends that APS use the most recent and regionally similar energy savings data available instead of the program-filed savings numbers from 2005. In addition, APS should incorporate results from its baseline study into its calculations. Staff believes that a time limit should be placed upon energy use measurements from other regions. Staff further recommends that APS use measured savings obtained from APS customers by the Measurement, Evaluation, and Research ("MER") contractor beginning no later than July 1, 2007. (Anderson Surrebuttal at 4). The averages of actual measured usage, for both standard and upgraded equipment, should be recalculated by the MER from usage samples for each prescriptive measure based on new measurements from the field no less frequently than every two years. (Anderson Direct at 11).

B. Whether The Commission Should Allow APS To Accrue Interest On The Demand-Side Management Adjustment Charge ("DSMAC") Account Balance.

Currently, the DSMAC account does not accrue interest. Staff does not oppose APS' proposal to allow the accrual of interest earnings on the DSMAC account balance. If interest is allowed to accrue, the applicable interest rate should be the one-year Nominal Treasury Constant Maturities rate that is contained in Federal Reserve Statistical Release H-15 or its successor publication.

C. What Action Should Be Taken If APS Fails To Spend The $30 Million For DSM During The Initial Three Year Period Identified In Decision No. 67744?

In rebuttal, APS witness Orlick addressed how to handle under-spending of DSM dollars in the 2005-07 period. She recommends that any under-spending should be carried over to and spent in subsequent years, in addition to the $16 million required to be spent in each subsequent year.

Staff's position is guided by Decision No. 67744, which provides that any unspent amount should be credited to the balance of the Demand-Side Management Adjustment Clause ("DSMAC") account if APS does not spend at least $30 million of the base rate allowance for approved and eligible DSM-related items during 2005-07. In effect, any "under-spending" is returned to ratepayers. (Anderson Direct at 7; Anderson Surrebuttal at 2).

XIV. ISSUES RELATED TO RENEWABLES

A. Increasing The Environmental Portfolio Standard Adjustor Rate To Recover Costs For The EPS Credit Purchase Program.

The Environmental Portfolio Standard ("EPS") requires distribution entities to derive a portion of their retail energy from environmentally friendly renewable sources. APS is able to meet some of its EPS requirements through the EPS Credit Purchase Program. The program allows APS to receive renewable energy credits for partially reimbursing customers who install renewable energy systems on their properties. APS recovers the costs for the EPS requirements through a Systems Benefit Charge and through the Environmental Portfolio Surcharge, an adjustment mechanism.

Staff recommends that the EPS adjustor rate and caps be increased to allow for more funding of the EPS Credit Purchase Program. The EPS adjustor rate should be set at $0.001392 per kWh with monthly caps per service of $0.56 for residential customers, $20.68 for non-residential customers, and $62.04 for non-residential customers with demands of more than 3,000 kW. This increased funding will provide an additional $4.25 million for the EPS Credit Purchase Program.

The recommended increase in the EPS adjustor rate and caps is reasonable because it is consistent with Commission Decision No. 68668. In that decision, the Commission approved the EPS Credit Purchase Program and ordered APS to allocate an additional $4.25 million for the EPS Credit Purchase Program, specifying that these additional funds should be recovered in rates in APS' ongoing general rate case.

B. Maintaining The Systems Benefit Charge For Renewables At $6,000,000.

Currently, APS' Systems Benefits Charge contains $6,000,000 for renewables. As mentioned before, the Systems Benefit Charge is one way that APS recovers some of the costs related to meeting its Environmental Portfolio Standard requirements. Staff recommends that the Commission maintain funding for renewables in the Systems Benefits Charge at $6,000,000.

C. APS' Proposed New Rate Schedule For Net Metering.

Net metering is a way to incent customers to invest in renewable energy generation by allowing their generation to offset their consumption over one or multiple billing periods. APS has a proposed new rate schedule for net metering: EPR-5, Rates for Renewable Resource Facilities of 10kW or Less for Partial Requirements. APS' proposed plan requires a bidirectional meter so that power flows both ways. With APS' proposed plan, customers that generate more electricity than they use will receive kWh credits for that excess energy in the subsequent billing period. This means that the customer will receive full retail value of the energy component of its bundled rate for the excess power that the customer provides to APS. EPS funding will be used to recover the metering costs, billing system modification costs, and revenue loss.

Staff recommends approving EPR-5 the following with modifications:

1) Staff would not require a bidirectional meter;

2) Staff recommends that the facility size limit be increased to 100kW;

3) Customer participation should not be limited by rate schedule;

4) The schedule should be modified to indicate that all changes to the schedule will require Commission approval;

5) APS should be required to clarify the tariff to indicate that ratepayers will be responsible for the cost of the meter.

(Keene Direct Test., hereinafter referred to as "Keene Direct", Ex. S-12 at 6-7).

In testimony, various parties have criticized Staff for its recommendation concerning the bi-directional meter. Although Staff believes that the Company should not be allowed to *require* a bi-directional meter as a condition to subscribing to this tariff, Staff recognizes that there may be benefits to using bi-directional meters in some circumstances. (Tr. at 3550). If using bi-directional meters is less expensive, if operational considerations indicate that bi-directional meters are preferable, or if long-term savings can be achieved by use of bi-directional meters, Staff would not be opposed to their use. *Id.* Certainly, Staff does not intend for its recommendation to foreclose the use of bi-directional meters in appropriate circumstances. *Id.* Nonetheless, Staff believes that achieving the objectives of the tariff at the lowest feasible cost is a reasonable consideration. The evidence presented in this proceeding demonstrates that two standard meters (one measuring outgoing electricity and one measuring incoming electricity) would appear to be less expensive than a bi-directional meter. (Keene Direct at 6).

In direct testimony, Staff witness Keene recommended that APS should be permitted to recover revenue loss associated with its proposed net metering tariff. (Keene Direct at 6; Tr. at 3577). At the hearing, however, she disagreed with APS' proposal for measuring revenue loss. (Tr. at 3577). Staff believes that the revenue loss is the difference between the retail rate and APS' avoided cost. (Tr. at 3510-11). Ms. Keene proposed that lost revenue should apply only to excess generation, not to total capacity; she further stated that actual retail rates should be applied, not an annual average *Id.* Avoided costs should reflect seasonal on-peak and off-peak rates, as on EPR-2 and EPR-4. *Id.* Finally, Staff witness Keene proposed that all metered rate schedules should be eligible. *Id.*

D. Green Pricing Tariffs.

APS is proposing two new rate schedules, Green Power Block Schedule (GPS-1A) and Green Power Percent Schedule (GPS-2A). Staff recommends approving the two new green pricing tariffs as proposed by APS.

APS' current Solar Partners Program allows customers to pay $2.64 per month for a block of 15 kWh of solar energy, which adds .0176 per kWh to the customer's current rate schedule. APS' proposed new tariff, GPS-1A, will allow customers to purchase 100kWh blocks of electricity generated by renewable resources and pay an additional $1.00 per month ($0.01 per kWh) for each block. It is reasonable to approve the GPS-1A tariff because APS is offering more energy from renewable resources at a cheaper price than the current program offers. GPS-2A offers customers the opportunity to determine the percentage of their electricity that will come from renewable resources. Customers will pay an additional price, depending on the percentage requested, on top of their current rate schedule. This tariff should be approved because the prices are reasonable ($0.01 per kWh for 100%; $0.005 per kWh for 50%; $0.0035 per kWh for 35%; $0.001 per kWh for 10%), and this program promotes the use of renewable energy.

XV. COST OF SERVICE STUDY

APS prepared a cost of service ("COSS") study 1) to perform jurisdictional allocations to separate the retail portion of APS' operations from the non-retail portion; and 2) to determine overall retail revenue requirements and to further allocate costs among customer classes. (Brosch Direct Test., hereinafter referred to as "Brosch Direct", Ex. S-7 at 5). APS conducted its COSS on a combined basis, performing jurisdictional and class allocations within a single model. *Id.* Although Staff generally found APS' COSS model to be reasonable, Staff has proposed one modification: Staff employed a Four Coincident Peak and Average ("4CP & Average") allocation in place of the Company's Four Coincident Peak ("4CP") method. *Id* at 7-8.

Staff's modification centers around the proper method for allocating production demand costs, which are the costs associated with the Company's nuclear, coal, and gas-fired generation facilities. *Id.* at 8, 10-11. Staff believes that the Company's COSS should use an energy-weighted allocation approach, instead of the Company's proposed 4CP method, which allocates production demand costs based solely upon relative class demands registered during the four peak hours of the year. *Id.* at 8. Staff therefore modified the Company's COSS to use a 4CP & Average allocation for production plant investment and expenses. *Id.*

Coincident peak demands are the measured maximum combined loads of all customers on the system in the single hour (or four hours under the Company's proposal) when overall system demand is the highest during the year. *Id.* The Company's proposed 4CP allocation factor would use these hourly demands registered by each customer class during the four highest peak system demand hours in the test year to allocate responsibility for *all* power generation production resources among customer classes. *Id.* Customer use during the remaining 8,756 hours of the year has no impact upon the allocation of costs for APS power plants under the 4CP approach. *Id.* The theory assumes that meeting hourly peak demand is the sole planning criteria used by APS to determine whether to incur generation fixed costs. *Id.* at 8-9.

Staff does not accept this premise. *Id.* at 9. Costs of APS' power production facilities are not incurred solely to meet peak hour demands, but are instead incurred to efficiently produce electricity throughout the entire year. *Id.* Although APS is a summer peaking utility, its generation facilities are also required to serve customers during all of the non-peak hours of the year. *Id.* at 11. Many of the costs incurred by APS to own, operate, and maintain its power plants could be much lower if the Company were concerned only with meeting demands during the four peak hours of the year. *Id.* at 11-12.

Generally, the effect of using an energy-weighted 4CP & Average approach (as recommended by Staff) is to recognize that demands throughout the year contribute to cost causation and to attribute some generating capacity costs to the lighting classes and to attribute more production costs to higher load factor customers that use more energy relative to their peak demands. *Id.* at 10. In APS' case, the 4CP allocation of production demand costs results in Street Lighting and Dusk to Dawn lighting classes paying nothing toward the fixed costs of APS' production facilities. *Id.* at 12. While it is obvious that APS must use its generation facilities to serve these customers, the 4CP method fails to allocate any production demand costs to them simply because their loads do not occur coincident with the four hours when the 4CP method measures customer demand. *Id.* at 12-13.

An energy-weighted allocation factor considers the fact that electric production facilities are designed and operated to meet both peak and non-peak demands. *Id.* at 13. The 4CP & Average approach involves a weighted combination of the peak demand allocation factor used by APS along with an average demand (or energy-based) allocation factor. *Id.* Although Staff proposes to apply weight to customer demands throughout the year, Staff nonetheless proposes to heavily weight hourly peak demands when determining production demand allocation factors. *Id.* at 9.

Staff witness Brosch explained that, in the last APS rate case, Staff and RUCO opposed the Company's use of a 4CP production demand cost allocation method and also noted that other Arizona utilities with summer peaking characteristics, such as Tucson Electric Power, have employed a 4CP & Average approach in proceedings before the Commission. *Id.* at 16-19.

Staff anticipated that APS would argue that Staff's 4CP & Average method would shift costs away from retail customers and inappropriately place them upon non-jurisdictional, FERC-regulated services. *Id.* at 22. Therefore, Staff elected to not disturb the jurisdictional allocation of production plant, so that no jurisdictional shifting of costs could occur. *Id.* The 4CP & Average calculation performed by Staff was limited to revision of the retail class allocation factors so that the percentage of production demand related costs allocated to FERC jurisdictional customers is unchanged and is still based upon the Company's proposed 4CP method. *Id.*

Finally, transmission costs in the COSS are treated as entirely non-jurisdictional. APS' retail customers are charged for transmission services for native load at the FERC Open Access Transmission Tariff rate. *Id.* at 23. This treatment is consistent with the resolution of APS' last rate case. *Id.*

XVI. RATE DESIGN

A. Interclass Returns For Residential Service Category Recommendations.

In general, Staff favors a rate spread that is informed by the results of the cost of service study as opposed to an across-the-board increase, as recommended by RUCO witness Diaz-Cortez. Staff recommends a total increase of 9.69 percent for the residential class as a whole, which is greater than the system average. Staff also recommends that residential rates EC-1, ET-1, and ECT-1 receive greater than average increases because these rate classes are underperforming relative to the rest of the residential class as well as the system average rate of return. Staff also recommends that E-12 receive an increase that is less than the system average because this rate class is earning slightly more than the system average.

Staff considered two scenarios in determining the proper rate spread for the interclass residential cost-of-service categories. The first scenario takes into account the elimination of frozen rate schedules E-10 and EC-1, consistent with Commission Decision No. 67744. In the second scenario, Staff evaluated an interclass residential rate spread where E-10 and EC-1 would not be cancelled in this proceeding. Staff recommends the first scenario and included the second scenario for information purposes only. A chart providing interclass residential rate spreads can be found in Staff witness Andreasen's testimony. (Andreasen Direct Test., hereinafter referred to as "Andreasen Direct", Ex. S-22 at 6).

B. Interclass Returns For General Service Category.

Staff's testimony addresses the rate increase percentage to apply to the general service category. Staff recommends a total increase of 9.52% for the general service class as a whole, which is less than the system average increase.

Staff recommends a smaller than average increase for E-20, which is reasonable because E-20's rate of return is greater than the system average and exceeds that of any other general service rate category, according to the cost-of-service review presented by Staff witness Brosch. Staff further recommends that the cost of service category E-32 (1,000 kW or greater) receive a greater increase than all other E-32 cost-of-service categories because this category is underperforming relative to the other E-32 cost-of-service categories. Staff also recommends a higher than average increase for both E-34 and E-35 because both of these rates have significantly lower average rates of return compared to the rest of the general service category and the system average rate of return. A chart providing an interclass general service rate spread can be found in Staff witness Andreasen's testimony. (Andreasen Direct at 7).

C. Customer Transition Plan For Residential Customers On E-10 And EC-1.

Staff's testimony addresses the elimination of frozen rate schedules E-10 and EC-1. The Commission provided for the cancellation of E-10 and EC-1 in Decision No. 67744 in April, 2005. APS proposes that residential customers subscribing to these rate schedules be given six months to review and choose a new rate schedule after this case concludes. By contrast, Staff recommends that residential customers on these rate schedules be given one year instead of six months to choose a new rate schedule, that APS continue to educate these customers on their rate options during the one-year period, and that APS wait until the end of the one-year transition period to cancel E-10 and EC-1. A one-year transition period is reasonable because the increase is fairly significant, and customers may need a longer period to evaluate all other available rate options, including time-of-use and demand options. For the evaluation period to be effective, APS should continue to educate its customers. In the rebuttal testimony of APS witness Rumolo, APS accepted Staff's proposal for the one-year transition period for residential customers on E-10 and EC-1. (Rumolo Rebuttal Test., Ex. APS-70 at 7).

Under APS' proposal, E-10 and EC-1 customers will be moved to default rates if they fail to elect a new rate during the transition period. E-10 and EC-1 customers who consume less than 1,000 kWh would be moved to E-12, E-10 customers who consume more than 1,000 kWh would be moved to ET-1, and EC-1 customers who consume more than 1,000 kWh would be moved to ECT-1. Staff finds this proposal to be reasonable.

D. Customer Transition Plan For General Service Customers On The Experimental Time-Of-Use Rates E-21, E-22, E-23, and E-24.

Staff's testimony addresses whether APS should be permitted to automatically switch general service customers on the experimental time-of-use rates E-21, E-22, E-23, and E-24 to a default rate at the conclusion of the rate case. Under APS' proposal, the default rate would be E-32 TOU. APS would then provide each customer with a comparison of his/her bill on E-32 and E-32 TOU. If a customer were to find that E-32 is a more advantageous rate than E-32 TOU, the customer could switch to E-32 as soon as a meter change out could be provided by APS.

Staff recommends that APS first give customers a six-month transition period to evaluate and choose among the various rate options. APS shall then cancel E-21, E-22, E-23, and E-24 at the end of the six-month interim period. This recommendation is reasonable because a six-month interim period provides customers the opportunity to consider all of their rate options before APS places them on a default rate, and it gives APS time to make the required meter change outs. Additionally, an interim period will mitigate unintended rate impacts by giving each customer the opportunity to choose the most economic rate option based on factors specific to his/her individual load pattern. In the rebuttal testimony of APS witness Rumolo, APS accepted Staff's proposal for the six-month transition period for general service customers on experimental rates E-21, E-22, E-23, and E-24. *Id.*

E. Rate Design For ET-2 & ECT-2.

Staff recommends that rate designs for ET-2 and ECT-2 remain revenue neutral compared to ET-1's and ECT-2's respective adopted rates. Regarding ET-2, Staff also recommends that the Commission incorporate off-peak kilowatt-hour winter rates that are less than off-peak summer rates. This approach is appropriate because a utility's generation or purchased power costs are typically lower in the winter than they are in the summer. This approach is also consistent with other APS off-peak rate designs.

F. Demand Rates And Structure Of E-32.

APS has proposed applying an increase of about 21% to rate schedule E-32, which is the proposed system average increase. Staff recommends that demand rates not be raised significantly over levels proposed by APS. Staff's hesitation to raise demand rates significantly is supported by two factors: 1) the last rate case significantly raised the demand charge for customers above 20 kw, such that some lower load factor customers received increases significantly greater than the average increase; and 2) this adoption of a higher demand rate is fairly new in that current rates have only been in effect for a year and a half.

AECC witness Higgins has recommended various demand rate alternatives that would recover additional revenue requirements through demand rates as opposed to energy rates. Increasing demand rates favors higher load factor customers. Staff believes that the Commission should be cautious about adopting higher demand rates for E-32 that would adversely impact low load factor customers, who have recently experienced greater than average increases as a result of APS' last rate case.

In addition to restricting the proposed demand rates, Staff also recommends that the Commission require APS to propose in its next rate case a replacement for E-32 with three separate tariffs for small, medium, and large general service categories or other appropriate divisions. Replacing E-32 with three separate tariffs is a reasonable modification because the current structure complicates the rate design process for E-32, making it difficult to tailor rate structures to different size customers with similar usage characteristics. Dividing E-32, which currently serves about 96% of APS' general service customer base, into size-based categories would mitigate this problem.

Staff witness Andreasen noted that creating multiple size-based categories for general service customers is common in the industry. Utilities often opt to have multiple rates for general service customers designed by different categories of size, rather than one rate structure that applies to customers of varying sizes. Staff believes that APS and its general service ratepayers could both benefit from rate schedules that are designed for groups of customers of similar sizes. In rebuttal testimony, APS witness Rumolo and DEAA witness Murphy both accepted Staff's proposal to divide E-32 into size-based categories.

G. Rate Structure of E-32 TOU

Staff agrees with DEAA witness Murphy that E-32 TOU should also be replaced with size sensitive rates. (Murphy Rebuttal Test., Ex. DEAA-2 at 2). Consistent with Staff's recommendation for E-32, Staff therefore recommends that APS file three separate tariffs for small, medium, and large general service categories (or other appropriate divisions) in its next rate case. Staff believes that the E-32 TOU rate structure should correspond to the E-32 rate structure; therefore, APS' future proposals for replacement tariffs for E-32 and E-32 TOU should be consistent.

Staff also agrees with AECC witness Higgins that the same rate increase applied to E-32 should also be applied to E-32 TOU in order to maintain the same relationship between the two schedules that was established in the last rate case. (Higgins Direct Test., Ex. PDMC/ARCC-5 at 17). Staff finds no evidence to support an increase for E-32 TOU that is significantly higher than the increase assigned to E-32.

H. System Benefits Charge.

Staff recommends that the System Benefits Charge be $49,191,690. Staff recommends the same amounts for demand-side management, renewables, and Palo Verde Power Plant

Decommissioning that APS has proposed. Staff recommends a higher amount than APS proposes for the E-3/E-4 Low Income Programs to take into account the $150,000 administrative and marketing expenses that APS identified in discovery. APS recommended including $10,177,404 for ISFI, but Staff recommends reducing that amount to $9,917,657. This proposed reduction of $259,747 is addressed in the Direct Testimony of Staff witness Dittmer. Staff recommends that the System Benefit Charge for all applicable APS rate schedules be set at $.001850 per kWh.

I. Schedule 1 Recommendations

Schedule 1 is a rate schedule that sets forth APS' terms and conditions of service. APS has proposed making certain clarifying changes as well as changing the way the after-hours charge for other services is collected from customers. APS' proposal would change the way in which the after-hours charge for other services is assessed to customers and would result in a charge of $75.00 per crew person per hour.

Staff believes that APS' proposal has the potential to create customer confusion and that customers will not be able to know ahead of time what they will be charged. Therefore, Staff recommends that the after-hours charge on Schedule 1 for other services remain at $75.00 per trip.

Staff recommends that the wording for sections 4.3.2.3.4, 5.4, and 6.4 on Schedule 1 included on APS document number 10679 be adopted, which can be found in Staff witness Andreasen's Surrebuttal testimony as Exhibit A. Additionally, Staff recommends that APS should include a definition for "Multi-Unit Residential High-Rise Developments" to avoid confusion.

J. Schedule 3 Recommendations

Schedule 3 is a service schedule that sets forth APS' line extension policy. Schedule 3 allows APS to collect the costs of installing distribution-related facilities that are associated with the development of new homes and businesses within APS' service territory. APS is proposing to move from a free-footage-based allowance to a dollar-based allowance. This proposal would improve APS' ability to recover its distribution costs associated with new growth. (Andreasen Direct at 22).

APS has reorganized Schedule 3 by specific type of end-use development: (1) Residential Homebuilder Subdivisions, (2) Residential Customer Home "Lot Sale" Developments, (3) Master Planned Community Developments, and (4) Residential Multi-Family Developments. For the Residential Custom "Lot Sale" Developments, Staff recommends that APS add clarifying language to Schedule 3 to specify that the "construction cost" refers to the "backbone infrastructure cost." Under sections titled "Master Planned Community Developments" and "Residential Multi-Family Developments," Staff recommends that APS clarify the allowances that will be credited to the applicant. With respect to the definition section of Schedule 3, Staff recommends that APS amend its definition for "Residential Homebuilder Subdivision" on Schedule 3 to be consistent with R14-2-201(34). Staff also recommends that APS add language to each section of Schedule 3 clarifying the applicable timeframes for field audits and refundable advances.

In rebuttal, APS witness Rumolo provided a redlined exhibit DJR-3RB, which adopts Staff's recommendations for Schedule 3. Staff finds this acceptable subject to the following three recommendations: (1) clarify that under section 1.1.1 of Schedule 3, "group" would be defined as "4 or less homes" instead of "less than 4 homes"; (2) clarify that under section 1.3.1, the allowance would be credited against the "total construction costs"; and (3) clarify that under section 1.3.2., advances would be subject to refund as specified in "section 4.1" instead of "section 4.2." In the rejoinder testimony of APS witness Rumolo, APS agreed that these recommendations are acceptable.

XVII. MISCELLANEOUS ISSUES

X. Hook-Up Fees.

Staff surveyed and researched the feasibility of establishing a hook-up fee for APS. There are many unanswered questions that should be addressed before the Commission decides this question. Therefore, Staff does not recommend the adoption of hook-up fees for APS at this time.

If the Commission chooses to pursue hook-up fees for electric and gas utilities, Staff recommends that the Commission open a generic docket where parties can provide feedback, and the

Commission can evaluate the adoption of hook-up fees for the energy industry. If the Commission were to adopt a hook-up fee for APS in this proceeding, Staff believes that the structure of Schedule 3 should be changed 1) to remove the free allowance and 2) to account for specialized distribution related costs in excess of those included in the hook-up fee.

B. Demand Response And Load Management.

Demand response programs are mechanisms designed to provide incentives for customers to reduce their load in response to prices, market conditions, or threats to system reliability. Demand response can result in savings of variable supply costs during times when wholesale prices and demand are high. This would displace the need to build additional capacity-related infrastructure, such as generation, transmission, and distribution. This would also improve system reliability by reducing demand when facilities, such as a generator or transmission line, fail. Load management refers to deliberate actions initiated by a utility to reduce peak demands or to improve system operating efficiency.

Staff recommends that APS conduct a study to identify the types of demand response and load management programs that would be most beneficial to APS' system. In the study, APS should demonstrate why certain programs are more beneficial than others, and it should also identify the customer segments that are most likely to respond to such programs. The study should rely on a cost-benefit analysis based on the Societal Cost Test and should be filed with the Commission within eight months of a Commission decision in this matter. If APS needs more than eight months to complete its study, Staff would not object to extending the deadline.

In addition, APS should be required to file for Commission approval one or more cost effective demand response or load management programs that APS believes would be most beneficial to its system and its ratepayers. APS should file its proposed program concurrently with the study referred to above.

C. Rate Stabilization Fund

The Commissioners asked the parties to address whether APS should establish a rate stabilization fund. Although a rate stabilization fund is a novel idea with potential benefits, Staff does not support the adoption of such a mechanism for APS at this time. (Rowell Rate Stabilization Response to Comm'rs., Ex. S-21).

A rate stabilization fund would require up-front funding from ratepayers, thereby front-loading the necessary costs. Furthermore, given the size of recent actual and requested APS rate increases, any hypothetical rate stabilization fund would have had to have been very large (and thus very expensive) to achieve any meaningful rate impact. With respect to SRP's rate stabilization fund, Staff notes that SRP is a fundamentally different entity than APS; thus, policies that are appropriate for SRP may not be appropriate for APS.

D. Depreciation

Staff concluded that the depreciation rates presented in APS witness White's Attachments REW-1 and REW-2 should be adopted for use in this case. (Smith Direct Test., Ex. S-18 at 34). These depreciation rates were developed in a manner that is consistent with the Commission's rules for depreciation rates. *Id.* at 35. These rates are also consistent with a "technical update" approach to the depreciation rates approved by the Commission in Decision No. 67744. *Id.* The net change in percentage terms is fairly small, resulting in an increase of .06 percentage points for APS plant and a decrease of .2 percentage points for plant that APS acquired from PWEC. *Id.*

The Commission should require APS to clearly break out each of the new depreciation rates between 1) a service life rate and 2) a net salvage rate, similar to the rates shown in Appendix A to Decision No. 67744. By doing this, the depreciation expense related to including the estimated future cost of removal can be tracked and accounted for by plant account. *Id.* Finally, Staff also recommends that the Commission consider amending A.A.C. R14-2-102, the Commission's rule addressing depreciation, to allow alternative treatment for the cost of removal. *Id.* at 34.

E. Staff Engineering Report

Staff conducted an engineering inspection to determine whether APS' 2005 capital improvements were used and useful and to evaluate APS' plant for quality of service purposes. (J. Smith Direct Test., Ex. S-2 at 6-7). Staff concluded that the utility plant improvements constructed by APS in 2005 were appropriate and necessary to maintain reliable, efficient, and cost effective service to its retail customers and the wholesale market. *Id.* Staff therefore concluded that all utility plant contained in APS' rate application is "used and useful" in meeting customers' needs. *Id.*

XVIII. CONCLUSION

For the reasons set forth above, Staff requests that the Commission adopt Staff's recommendations in this matter.

RESPECTFULLY SUBMITTED this 22nd day of January, 2007.

Janet Wagner

Christopher C. Kempley, Chief Counsel
Janet Wagner, Senior Staff Counsel
Charles Hains, Attorney
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Original and 17 copies of the foregoing filed this 22nd day of January, 2007 with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Copy of the foregoing mailed this 22nd day of January, 2007 to:

Deborah R. Scott
Kimberly A. Grouse
SNELL & WILMER
One Arizona Center
400 East Van Buren Street
Phoenix, AZ 85004-2202

Thomas L. Mumaw
Karilee S. Ramaley
PINNACLE WEST CAPITAL CORPORATION
Post Office Box 53999, MS 8695
Phoenix, AZ 85072-3999

C. Webb Crockett
Patrick J. Black
FENNEMORE CRAIG, P.C.
3003 North Central Avenue, Suite 2600
Phoenix, AZ 85012-2913

Michelle Livengood
UniSource Energy Services
One South Church Street, Suite 200
Tucson, AZ 85702

Steven B. Bennett
Deputy City Attorney
City Attorney's Office
3939 North Drinkwater Boulevard
Scottsdale, AZ 85251

George Bien-Willner
3641 North 39th Avenue
Phoenix, AZ 85014

Michael W. Patten
J. Matthew Derstine
Laura E. Sixkiller
ROSHKA DEWULF & PATTEN, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, AZ 85004

Michael L. Kurtz
BOEHM, KURTZ & LOWRY
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

Scott S. Wakefield
RUCO
1110 West Washington Street, Suite 220
Phoenix, AZ 85007

Lawrence V. Robertson, Jr.
Post Office Box 1448
Tubac, AZ 85646

Bill Murphy
Murphy Consulting
5401 North 25th Street
Phoenix, AZ 85016

Andrew W. Bettwy
Karen S. Haller
Assistants General Counsel
Legal Affairs Department
5241 Spring Mountain Road
Las Vegas, NV 89150

Amanda Ormond
The Ormond Group LLC
Southwest Representative
Interwest Energy Alliance
7650 South McClintock, Suite 103-282
Tempe, AZ 85284

Joseph Knauer, President
Jewish Community of Sedona
and the Verde Valley
100 Meadowlark Drive
Post Office Box 10242
Sedona, AZ 86339-8242

David C. Kennedy, Esq.
818 East Osborn Road, Suite 103
Phoenix, AZ 85014

S. David Childers, Esq.
LOW & CHILDERS
2999 North 44th Street, Suite 250
Phoenix, AZ 85018

Tracy Spoon
Sun City Taxpayers Association
12630 North 103rd Avenue, Suite 144
Sun City, AZ 85351

Tammie Woody
10825 West Laurie Lane
Peoria, AZ 85345

Douglas V. Fant
Law Offices of Douglas V. Fant
3655 West Anthem Drive, Suite A-109
Anthem, AZ 85086

Gary Yaquinto, President
Arizona Utility Investors Association
2100 North Central Avenue, Suite 210
Phoenix, AZ 85004

Sein Seitz, President
Arizona Solar Energy Industries Association
3008 North Civic Center Plaza
Scottsdale, AZ 85251

Dan Austin
Comverge, Inc.
6509 West Frye Road, Suite 4
Chandler, AZ 85226

Timothy M. Hogan
Arizona Center for Law in the Public Interest
202 East McDowell Road, Suite 153
Phoenix, AZ 85004

Jay I. Moyes
Moyes Storey Ltd.
1850 North Central Avenue, Suite 110
Phoenix, AZ 85004

Kenneth R. Saline, P.E.
K.R. Saline & Assoc., PLC
160 North Pasadena, Suite 101
Mesa, AZ 85201

Robert W. Geake
Vice President and General Counsel
Arizona Water Company
Post Office Box 29006
Phoenix, AZ 85038-9006

Lieutenant Colonel Karen S. White
Chief, Air Force Utility Litigation Team
AFLSA/JACL-ULT
139 Barnes Drive
Tyndall AFB, FL 32403

Greg Patterson
Arizona Competitive Power Alliance
916 West Adams Street, Suite 3
Phoenix, AZ 85007

Jim Nelson
12621 North 17th Place
Phoenix, AZ 85022

Barbara Klemstine
Brian Brumfield
Arizona Public Service
Post Office Box 53999, MS 9708
Phoenix, AZ 85072-3999

Jon Poston
AARP Electric Rate Project
6733 East Dale Lane
Cave Creek, AZ 85331

Coralette Hannon
AARP Government Relations & Advocacy
6705 Reedy Creek Road
Charlotte, NC 28215

Rosean Osorio